BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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	:	APPLICATION DOCKET NO. A - 110550F0160

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VOLUME IV

PECO STATEMENT NO. 3 -
DIRECT TESTIMONY OF WILLIAM H. HIERONYMUS

PECO STATEMENT NO. 3

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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	:	DOCKET NO. A-

DIRECT TESTIMONY

OF

WILLIAM H. HIERONYMUS

Date: February 4, 2005

DIRECT TESTIMONY OF WILLIAM H. HIERONYMUS

Q. What is your name and business address?

A. My name is William H. Hieronymus. I am a Vice President of Charles River Associates Incorporated. My office address is 200 Clarendon Street, T-33, Boston, MA 02116.

Q. Please briefly outline your professional experience.

A. For the past 30 years I have specialized primarily in economic, business and regulatory issues concerning the electricity and natural gas industries. For the past 17 years the primary activities in which I have been involved relate to restructuring the electricity industry into a more market-oriented paradigm. Market power has been a key focus of my consulting. I have helped to draft market power-related portions of Independent System Operator ("ISO") and Regional Transmission Organization ("RTO") tariffs, commented upon proposed tariff revisions and advised clients on the regulatory implications of mergers and acquisitions. I have testified before the Federal Energy Regulatory Commission ("FERC") and, in many instances, state regulatory commissions, with respect to market power implications of approximately 20 mergers, including the merger of PECO and Unicom that resulted in the formation of Exelon. My resume is contained in Exhibit J-2 of the attached FERC testimony.

Q. What is the purpose of your testimony?

A. I have been asked by Exelon and PSEG to address the potential competitive impact of their proposed merger on electric and natural gas markets. As I understand it, Section 2811 (e) of the Public Utility Code (66 Pa. C.S. § 2811(e)) provides that the Pennsylvania Public Utility Commission ("Commission") shall consider whether a proposed merger or consolidation of 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 electricity customers in this Commonwealth from obtaining the benefits of a properly functioning and workable competitive retail electricity market."

Similarly, Section 2210(a) of the Public Utility Code (66 Pa. C.S. § 2210 (a)) provides that the Commission shall consider whether a proposed merger or consolidation involving natural gas distribution companies or natural gas 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."

Q. **Have you conducted an analysis of the effect of the Exelon/PSEG merger on competition?**

A. Yes. I conducted that analysis as part of their application to the FERC requesting approval of the merger. A copy of my Direct Testimony in that docket is attached as Exhibit WHH-1 hereto and is incorporated herein.

The analysis that I conducted accords with the FERC's Competitive Analysis Screen as described in Appendix A to the Merger Policy Statement, as further modified in Order No. 642 and the revised filing instructions in Section 33 of FERC's Regulations. The FERC analysis is intended to comport with the Department of Justice and Federal Trade Commission Horizontal Merger Guidelines. The primary focus of my analysis is on potential horizontal market power effects (e.g., for the electric business, those arising from the combination of electric generating assets). I also address vertical effects concerning barriers to entry that might interfere with the long-run competitiveness of the wholesale market for electricity.

Q. Please describe the results of your analysis.

A. As described in my testimony to FERC, the merger of two large generators in the Eastern portion of PJM would, absent mitigation, raise serious market power issues. However, the Joint Petitioners propose to mitigate these potential effects by divesting control of 5,500 MW of generation, of which at least 5,300 MW is in the PJM East market.[1] The divestiture is in the form of 1) virtual divestiture of the equivalent of 2,600 MW of nuclear generation, and 2) outright divestiture of 2,900 MW of intermediate and peaking fossil generation. The divestiture of fossil generation will be to no less than two parties, neither of whom can have a significant share of generation ownership in PJM East or Expanded PJM. The nuclear divestiture will be a combination of a long-term (at least 15 year) sale of output to a third party and/or an auction of firm 7X24 nuclear energy into PJM East on a rolling three-year basis. The auction will be in 25 MW blocks; this is intended to facilitate competition to serve retail load. As with the fossil auction, there will be limitations on who can acquire how much of the nuclear energy that

[1] For purposes of my FERC testimony and analysis, I refer to a number of variants of PJM. I use *PJM Mid-Atlantic* to refer to the original PJM, *PJM Pre-2004* to refer to original PJM members in the Mid-Atlantic Area Council ("MAAC") plus Allegheny Energy. *Expanded PJM* refers to the combination of PJM Pre-2004 plus the new members, namely ComEd, AEP, Dayton Power & Light and Duquesne (all of which have integrated into PJM during 2004 and 2005), and Dominion Virginia Power ("DVP") that is expected to integrate into PJM in 2005. The Mid-Atlantic portion of PJM, at times, has been characterized as having three submarkets reflecting the predominant west-to-east energy flow and the three high-voltage interfaces within the region: West, Central and East. These are referred to as PJM West, PJM Central and PJM East, respectively.

are intended to assure that the divestiture is deconcentrating. The virtual divestiture of nuclear generation will continue for the life of Exelon's and PSEG's PJM East nuclear units, that is, it will be extinguished on a megawatt-by-megawatt basis as such generation is decommissioned, derated or sold. As also described in my FERC testimony, the Joint Petitioners have proposed interim mitigation to bridge the period between completing the merger and the completion of the fossil and nuclear divestiture.

Q. What geographic markets did your analysis cover?

A. The most critical market is the PJM East market. This is a constrained market roughly 200 hours per year. It also is the market in which the bulk of PECO's and PSEG's generation is located. I also looked at the PJM market as it existed prior to the major expansion of the past 12 months (i.e., PJM "classic" plus Allegheny Power). This market includes all of the generation that historically belonged to PSE&G and to PECO that formerly was used to meet their loads. Finally, I examined Expanded PJM, the whole of PJM as it is expected to be by the time the merger is completed. This market includes additional PSEG and Exelon generation, including the generation that is used to meet Commonwealth Edison's retail load. In each case, the market includes imports, limited to the simultaneous transmission limit into the market area.

Q. What products did your analysis cover?

A. FERC's analysis focuses primarily on electric energy. Two measures of a supplier's size are considered: Economic Capacity and Available Economic Capacity. The former is the whole of generation controlled by a supplier and the latter measures the supplier's share of the market after netting off the generation that is used to meet affiliated retail and requirements load. FERC considers Economic Capacity the more important of the two. This is particularly true in an area, such as PJM East, where there is full retail access and where, indeed, it is not possible to even know from available data which and how much generation is committed to retail customers on a long-term basis.

While the main focus is on electric energy, I also examined the effect of the merger on capacity markets (both as currently designed and as planned after the new Reliability Pricing Model comes into being)[2] and ancillary services markets.

Q. What is the Reliability Pricing Model?

A. The Reliability Mechanism is the replacement for the existing capacity market (UCAP or ICAP) in PJM. While details are not all firmed, and indeed remain contentious among PJM members, it is expected to feature a demand curve mechanism similar to the NYISO, a four-year forward market (and supplemental markets closer to the applicable time) and regional markets where necessary. As discussed in my FERC testimony, the current ICAP/UCAP market is PJM-wide and the likely markets beginning in 2007/8 will include a PJM-East market. These are the markets that I have analyzed.

Q. How is the energy market analysis conducted?

A. Consistent with the Merger Guidelines, the analysis focuses on market structure. The specific metric used is the Herfindahl-Hirschman index (HHI). To compute the index, each supplier's market share is squared and then summed. If the sum is

[2] As of this time, PJM expects to file its new Reliability Pricing Model (the ICAP replacement) proposal in March 2005, requesting Commission approval in time to begin forward auctions this fall.

less than 1000 (post merger), the equivalent of a market with ten equal-sized participants, any merger passes. If the sum is between 1000 and 1800, the screen is passed so long as the increase in the HHI is 100 points or less. Examples of a 100 point increase would be a firm with a 5 percent share merging with a firm with a 10 percent share, or a firm with a 2 percent share merging with a firm with a 25 percent share. Finally, if the HHI is above 1800, an increase of 50 points passes the screen and an increase between 50 and 100 points may or may not, depending on the circumstances.

Because conditions vary by time of day and season, FERC requires applicants to perform the analysis using numerous "snapshots" reflecting differing market conditions. For example, in the summer super peak period, essentially all generation is economic and counted as being in the market. Conversely, in spring overnight periods, only deep baseload generation is economic and considered to be in the market. In all, my analysis looks at 10 time periods, ranging from off-peak in the spring and fall to the highest load hours in the summer.

Q. **Taking into account the mitigation that Applicants have proposed, what is the effect of the merger?**

A. Mitigation has been designed to assure that none of the screens for any of the products that FERC demands be considered is violated. These products include energy, capacity and spinning reserves.

Q. **Does FERC require examination of any other merger effects other than horizontal concentration?**

A. Yes. FERC also is concerned about the potential vertical market power effects of mergers. Vertical effects relate primarily to using market power in one activity to enhance ones position (or impede competitors) in another activity. The areas of FERC concern primarily are electric and gas transmission that might be manipulated to disadvantage competitors in the wholesale electricity market. As with horizontal effects, what matters is the change in the ability or incentive to abuse one's position arising from the merger.

In this case, there is no concern about electric transmission. PSE&G's and Exelon's electric transmission is controlled by PJM and there is no basis for concern that the companies, who are passive owners, could use transmission to disadvantage competitors. Likewise, there is no real concern with gas transmission. Both PECO and PSE&G have gas distribution systems. However, they have little high-pressure transmission, none of it interstate. Relatively little competing generation is connected to these distribution systems and all of the competing generation is served under long-term contracts or discounted tariff rates. Moreover, tariff rates and conditions are subject to state regulation. New generation can, and generally does, connect directly to interstate pipelines.

FERC has concluded that both the upstream (pipeline) market and the downstream (electricity) market need to be highly concentrated (HHI greater than 1800) in order to raise vertical concerns. In examining downstream markets, FERC requires that gas-fired generation be attributed to the supplier (LDC or pipeline) to whom it is connected. In examining upstream markets, shares of gas transmission capacity are allocated to the holder of firm transportation rights. I examined the post-merger, post-mitigation upstream and downstream markets. There are screen failures in the downstream market. Because of a peculiarity of the required screen, the proposed divestiture of generation that cures screen failures in the electricity analysis does not cure these failures, despite that the downstream market is the electricity market. This is because divested gas-fired generation still is allocated to Exelon/PSEG for vertical analysis purposes since it still is connected to their distribution systems. However, the upstream market is not highly concentrated, so the conditions that FERC deems necessary for creating a vertical market power problem are absent.

Q. Will there be any effect from the merger on retail competitiveness in the electricity market?

A. No. PSEG has exited the competitive retail electricity business for reasons that are independent of this merger. The merger, therefore, does not eliminate a retail competitor.

Q. Will there be any impact arising from the merger on retail electric prices in Pennsylvania?

A. Any effect will be beneficial. The primary effect anticipated from the merger will be that the capacity factors for the PSEG-operated nuclear plants will increase. Increasing nuclear output will have a small but significant tendency to lower wholesale prices. This is because increasing the amount of energy at "the bottom of the stack" will in at least some hours lower the PJM marginal cost. This should lower LMP prices, particularly in PJM East. Lower LMPs will mean a reduced wholesale component of retail rates for all Pennsylvania customers being served out of the competitive wholesale market.

Q. **Are there any benefits to Pennsylvania of PSE&G's participation in the New Jersey BGS auction?**

A. Yes. For the past several years PSE&G has acquired energy and capacity to serve its retail load through the BGS auction. This experience likely will be of substantial value to PECO and to the Commission in developing and implementing the mechanisms for serving PECO's provider of last resort obligations when the rate cap period ends.

Q. **Based on your analysis, is the proposed merger likely to result in anticompetitive or discriminatory conduct that will prevent retail electricity customers in Pennsylvania from obtaining the benefits of a properly functioning and workable competitive retail electricity market?**

A. It follows from my analysis and conclusions that the proposed merger will not have these adverse effects.

Q. **Will there be any adverse effects on competition in gas arising from this merger?**

A. No. Neither company controls significant wellhead supplies or long distance, interstate pipelines. Both individually and collectively, they do not have a dominant share of pipeline capacity. Each company operates a gas distribution business. However, their franchise areas are separate and distinct, with PSE&G's in New Jersey and PECO's in Pennsylvania. PECO's franchise natural gas operations are fully regulated by this Commission. PSEG is withdrawing from the competitive retail gas business and serves no customers in Pennsylvania. Exelon is a minor supplier (other than to customers in its franchise area), serving only a few gas customers in Western Pennsylvania.

Q. **Based on your analysis, is the proposed merger likely to result in anticompetitive or discriminatory conduct that will prevent retail natural gas customers in Pennsylvania from obtaining the benefits of a properly functioning and effectively competitive retail natural gas market?**

A. No. While PECO operates a gas distribution system in four counties surrounding Philadelphia, PSEG does not own or control a natural gas system in the state nor participate in Pennsylvania gas markets in any way. Therefore the merger is not likely to change the structure or conduct of natural gas distributors or suppliers in Pennsylvania. Hence it is not likely to result in discriminatory or anticompetitive conduct that will prevent retail gas customers from obtaining the benefits of a properly functioning and effectively competitive retail natural gas market.

Q. **Is the merger likely to reduce the degree of competition between gas and electricity in Pennsylvania?**

A. No. PECO has overlapping service areas for gas and electricity. However, there is open retail access for both electricity and gas. More importantly, the fact that PECO is a combination utility is a pre-existing situation, unrelated to the merger. Since PSEG sells neither gas nor electricity to retail customers in Pennsylvania, and has no distribution network in the state for either product, the merger cannot have adverse competitive impacts on inter-energy competition.

Q. **Does this complete your testimony?**

A. Yes, it does.

EXHIBIT WHH-1 IS REFERENCED IN THIS SECTION AS EXHIBIT NO. J-1 (FERC TESTIMONY)

Exhibit No. J-1

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Exelon Corporation	)	
	)	Docket No. EC05-___-000
Public Service Enterprise Group Incorporated	)	

JOINT APPLICATION
FOR APPROVAL OF MERGER

PREPARED DIRECT TESTIMONY AND EXHIBITS OF
WILLIAM H. HIERONYMUS
ON BEHALF OF APPLICANTS

DIRECT TESTIMONY OF
WILLIAM H. HIERONYMUS

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I. PURPOSE, SUMMARY OF ANALYSIS AND CONCLUSIONS

Introduction

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is William H. Hieronymus. I am a Vice President of Charles River Associates Incorporated. My business address is 200 Clarendon Street, T-33, Boston, MA 02116.

Q. PLEASE SUMMARIZE YOUR RELEVANT PROFESSIONAL BACKGROUND.

A. For the past 30 years, the primary focus of my consulting has been on the electricity sector. For the past 17 years, I have worked primarily on the restructuring of the electricity industry from a fully regulated to a more competitively oriented model, both in the U.S. and abroad. Much of my time has been spent on market power issues. I have developed and commented on market power-related regulatory rules and Regional Transmission Organization ("RTO") (or foreign equivalent), on market power mitigation as well as on issues of market structure. I have testified before the Federal Energy Regulatory Commission ("Commission") and other regulatory bodies on market power on numerous occasions. This includes a number of mergers and acquisitions over the past dozen years, including approximately 20 mergers among electric utilities and "convergence" mergers of electric utilities and natural gas pipelines. Among these, I was Applicants' market power witness in Docket No. EC00-26-000, the merger of Unicom and PECO that formed Exelon Corporation. My resume is attached as Exhibit J-2.

Purpose

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have been asked by Exelon Corporation ("Exelon") and all its jurisdictional public utilities,[1] and Public Service Enterprise Group Incorporated ("PSEG") and all its

[1] These include, among others, PECO Energy Company ("PECO"), Commonwealth Edison Company ("ComEd"), and Exelon Generation Company, LLC ("Exelon Generation").

jurisdictional public utilities[2] (collectively, the "Applicants") to evaluate the potential competitive impact of the merger of Exelon and PSEG (creating Exelon Electric & Gas, or "EEG") on relevant electricity markets.[3] I performed the Competitive Analysis Screen described in Appendix A to the Commission's Merger Policy Statement ("Order No. 592"),[4] as modified in the Revised Filing Requirements Under Part 33 of the Commission's Regulations.[5] The Competitive Analysis Screen is intended to comport with the Department of Justice and Federal Trade Commission ("DOJ/FTC") Horizontal Merger Guidelines ("Guidelines"). I also have analyzed other electricity-related product markets (*e.g.*, ancillary services and capacity). I further provide analyses to show that the proposed mitigation cures all screen failures in all relevant markets.

The primary focus of my testimony is potential horizontal market power effects, *i.e.*, those arising from the combination of the electric generating assets owned or controlled by Exelon Generation and its affiliates and those owned or controlled by PSEG Power and its affiliates that potentially could create or enhance the merged firm's ability to increase prices in the electricity market. I also address vertical effects concerning barriers to entry that might undercut the presumption that long-run generation markets are competitive and, more generally, the potential to use control over fuel supply, fuel transportation facilities, or electric transmission to exert vertical market power by increasing rivals' costs.

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2 These include, among others, Public Service Electric and Gas Company ("PSE&G") and PSEG Power LLC ("PSEG Power").

3 The exhibits to the Application include a complete list of Applicants.

4 Order No. 592, *Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement*, FERC Stats. & Regs. (Regulations Preambles) ¶ 31,044 (1996), *on reconsideration*, Order No. 592-A, 79 FERC ¶ 61,321 (1997).

5 Order No. 642, Final Rule in Docket No. RM98-4-000, 18 CFR Part 33, 93 FERC ¶ 61,164 (2000) ("Revised Filing Requirements").

Summary of Analysis and Conclusions

Q. DOES YOUR ANALYSIS INDICATE THAT THE MERGER RAISES COMPETITIVE CONCERNS?

A. Once the proposed mitigation is taken into account, the merger does not raise competitive concerns. While the merging parties are each significant participants in energy markets in PJM Interconnection, L.L.C. ("PJM"), and particularly in PJM East,[6] where both PECO and PSE&G are located, Applicants have committed to a comprehensive mitigation plan that eliminates any merger-related competitive concerns that otherwise would be present. Also, a combination of market and regulatory conditions, technical operating constraints, and ongoing contractual commitments of the Applicants further limit any ability to exercise market power. My analysis focuses on expected market conditions in 2006.

Market and regulatory conditions. PJM operates the largest centrally dispatched, competitive wholesale electricity market in the United States. The market is well-functioning, and has in place comprehensive and Commission-approved market monitoring and mitigation procedures that mitigate concerns about generation and transmission market power. The PJM market monitor has the authority to deter, and has been effective in deterring, withholding or other attempts at market manipulation. Notably, the operation of PJM mitigation is essentially automatic whenever sub-areas within PJM are constrained.

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6 For purposes of my testimony and analysis, I refer to a number of variants of PJM. I use *PJM Mid-Atlantic* to refer to the original PJM, *PJM Pre-2004* to refer to original PJM members in the Mid-Atlantic Area Council ("MAAC") plus Allegheny Energy. This is the geographic area that PJM today treats as seamless for capacity market purposes. Further, according the State of the Market report, inclusion of APS has led to a substantial reduction in congestion between APS and the remainder of PJM, effectively moving the constraint further west. *Expanded PJM* refers to the combination of PJM Pre-2004 plus the new members, namely ComEd, AEP, Dayton Power & Light and Duquesne (all of which have integrated into PJM during 2004 and 2005), and Dominion Virginia Power ("DVP"), which is expected to integrate into PJM in 2005. The Mid-Atlantic portion of PJM, at times, has been characterized as having three submarkets reflecting the predominant west-to-east energy flow and the three high-voltage interfaces within the region: West, Central and East. These are referred to as PJM West, PJM Central and PJM East, respectively. However, West and Central are not treated as markets themselves, but are aggregated with markets to the east of them.

Technical operating constraints. A significant portion of Applicants' combined generation portfolio in PJM consists of nuclear generation and, to a lesser extent, baseload coal generation. As the Commission has recognized, the operating characteristics and regulatory oversight of nuclear units make them poor choices for withholding of output or other strategic bidding behavior, and the large amounts of competing low-cost coal capacity in the region make the profitability of withholding coal units unlikely.[7]

PECO and ComEd's continuing load and contractual commitments. All of PECO's retail electric customers have the right to choose a generation supplier.[8] Under the terms of a settlement, PECO's distribution rates are capped through December 31, 2006, and generation rates are capped through December 31, 2010. PECO meets its continuing load obligations through a full-requirements, Power Purchase Agreement ("PPA") with Exelon Generation. In 2003, PECO's peak load obligations were 6,531 MW, and its forecast peak load requirements for 2006 are 8,033 MW.[9] Thus, of Exelon Generation's approximately 11,000 MW of generation located in the Mid-Atlantic portion of PJM (prior to merger-related divestitures), the majority is committed to serving native load through 2010. At least through 2010, Exelon Generation perhaps has only a few thousand megawatts of "excess" generation in respect of its PECO load.

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[7] *See Ohio Edison Co.*, 94 FERC ¶ 61,291 (2001), *citing Commonwealth Edison Co.*, 91 FERC ¶ 61,036 (2000).

> As we stated in Commonwealth Edison, 91 FERC ¶ 61,036 at 61,134 n.42 (2000), it is difficult to engage in strategic dispatch of nuclear units, given their operating characteristics and stringent regulatory oversight. Further, it is likely that the opportunity cost associated with the merged firm shutting down its coal-fired units during off-peak periods in order to drive up the market price would outweigh the potential profit. Moreover, due to the large amount of low-cost capacity in the region, Applicants would have to withhold a significant amount of capacity in order to drive up the market price during the off-peak period.

The Commission recently reiterated its view with respect to the strategic dispatch of nuclear generation in *USGen New England, Inc.*, 109 FERC ¶ 61,361 (2004).

[8] As of January 1, 2005, approximately 7 percent of its customers (10 percent of customer load) was served by an alternative supplier. These customers continue to pay a delivery charge to PECO. http://www.oca.state.pa.us/cinfo/stats0105.pdf

[9] This peak load forecast is for PECO's load responsibility only, and does not include customers who are expected to have alternative suppliers. The high growth rate arises from the return of customers that PECO had

ComEd also continues to have provider of last resort ("POLR") responsibilities that continue at least to the end of 2006.[10] ComEd secures generation supply to serve its POLR responsibilities through a full-requirements contract with Exelon Generation. ComEd's three wholesale (full or partial) requirements customers are served under fixed-price contracts that run through 2007, and its retail customers have frozen bundled rates through 2006. Exelon Generation has about 15,000 MW of owned generation and purchase contracts to serve ComEd's expected approximately 18,000 MW of load in 2006. Thus, at least through 2006, Exelon has virtually no "excess" generation in respect of its ComEd load requirements.

In any event, Exelon has committed to hedge a minimum of 90 percent of its generation portfolio in the forward market. Moreover, for purposes of my analysis, I focus on Economic Capacity, that is, I ignore load or contractual commitments.

<u>PSEG Power's load and contractual commitments</u>. PSE&G procures resources to serve its load via the New Jersey Basic Generation Service ("BGS") auctions. Contracts have been secured to serve load in rolling three-year tranches, some of which extend into 2007. Affiliates of PSE&G participate as suppliers in the BGS auction, and are responsible for the supply of approximately 4,200 MW for the period June 2005 to June 2006 and 1,700 MW for the period June 2006 to June 2007, either directly as a winner in the BGS auction or indirectly as a supplier to other winners in the BGS auction. Additionally, PSE&G affiliates are serving 275 MW of Duquesne POLR load through May 2006 and have sold 500 MW of firm energy to FirstEnergy through 2008. Given PSEG Power's approximately 12,000 MW of generation in the Mid-Atlantic portion of PJM (prior to merger-related divestitures), these commitments reduce its uncommitted capacity to about 7,000 to 10,000 MW in 2006. Moreover, it is likely that PSEG will secure further commitments during the 2005 New Jersey BGS auction. Indeed, PSEG's publicly-stated

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auctioned off to third-party retail suppliers pursuant to decisions by the Pennsylvania Public Utility Commission ("PAPUC").

[10] In Illinois post-2006, it is expected that ComEd's power procurement to meet its POLR obligations will be subject to a competitive auction similar to the auction that is in place in New Jersey.

policy is to hedge a minimum of 75 percent of its portfolio 18 to 24 months in advance. As with Exelon, for purposes of my Economic Capacity analysis, I ignore PSEG's load and contractual commitments.

Applicants have committed to undertake a comprehensive series of measures to address market power concerns arising from this merger and to further enhance competition in PJM markets. I considered three relevant geographic markets within PJM: PJM East, PJM Pre-2004, and Expanded PJM.[11] Table 1 below summarizes the mitigation commitment in terms of equivalent capacity (summer ratings). No additional mitigation is required for Expanded PJM since the mitigation in the smaller markets also cures screen failures in this market.

Table 1: Mitigation Commitments (MW)

Generation Type	PJM East	PJM Mid-Atlantic*	Total
Nuclear	2,400	200	2,600
Mid-Merit**	1,900	0	1,900
Peaking	1,000	0	1,000
Total	5,300	200	5,500

* The additional 200 MW of commitment can be delivered anywhere in PJM Mid-Atlantic, including PJM East.

** At least 550 MW of the mid-merit divestiture will include coal-fired capacity. Also, within the mid-merit category, 1,200 MW must be economic at a $55/MWh market price.

There are two key elements of Applicants' mitigation plan: (1) divestiture of substantial coal, mid-merit and peaking capacity, and (2) virtual divestiture of nuclear baseload units through a combination of a) long term energy sales contracts or swaps with parties that do not have significant generating assets in PJM and b) an auction of rolling three-year firm contracts. To the extent nuclear baseload capacity in PJM East is divested or decommissioned the virtual divestiture requirement will be reduced equivalently. Applicants also have committed to mitigation measures in the PJM capacity markets.

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11 As discussed *infra*, there are no other relevant markets within PJM in the context of this transaction. I considered whether Northern New Jersey, or the Northern PSEG zone, is a relevant market and concluded that since Exelon owns no generation within its boundaries, it is not a relevant market.

Interim mitigation measures are proposed that will assure that market power potentially arising from the merger will not be exercised during the period before divestiture can be completed.

Virtual Divestiture. Applicants have committed to divest control over 2,600 MW of nuclear capacity through a combination of three year auctions of rights to the output (the Baseload Auction) and Long-Term Contracts. No single party will be eligible to purchase more than half of the 2,600 MW. Details of the proposed options are discussed in Mr. Cassidy's testimony. Under the Baseload Auction, Applicants will auction the firm energy equivalent of 2,400 MW of nuclear baseload capacity as firm energy (24x7) in 25 MW blocks delivered in PJM East (at an aggregate of Applicants' PJM East nuclear generation buses) for a rolling three-year period. An additional 200 MW of equivalent capacity will be subject to the Baseload Auction (or the Long-Term Contract), but may be delivered at the PJM West Hub, unless seller agrees to an alternate delivery point within PJM. In the initial auction, one-third of the mitigation amount will be sold for a one-year term, one-third for a two-year term, and one-third for a three-year term. In subsequent annual auctions, one-third of the mitigation amount will be sold for a three-year term. The timing of the auction will coincide with the New Jersey BGS auction, in order to facilitate competition in that auction.

Under the Long-Term Contract, Applicants will sell 15-year or longer entitlements to PJM East baseload energy (or swap PJM East baseload energy for baseload energy in a non-PJM market). Two alternative products will be available under this option. The first mirrors the Baseload Auction (*i.e.*, it is a firm 7X24 product), except that the term is for a minimum of 15 years following the close of the merger. The alternate product replaces the firm 24X7 must-take energy product delivered at the aggregate of Applicants' PJM East nuclear generation buses with a guarantee of delivery based on the performance characteristics of a designated PJM East nuclear facility. Applicants will guarantee delivery of an annual amount of energy based on the designated facility's historical capacity factor, and the contract will be for the lesser of the term of the contract (*e.g.*, 15 years) or the date that the unit is decommissioned. Any permanent plant deratings will be reflected in the contract terms. This alternate product will facilitate an energy swap agreement, if Applicants choose that option. The amount of a contract with any single party will be no more than one-half of the virtual divestiture amount. Additionally, suppliers with a market share of 5 percent or more of capacity in either PJM East or Expanded PJM will not be eligible for such bilateral contracts, nor will suppliers with market shares between 3 and 5 percent be permitted to purchase, in aggregate, more than 25 percent of the capacity to be divested or sold under long-term contract.

Mitigation will continue subject to the condition that the virtual divestiture requirement will be extinguished, megawatt for megawatt, to the extent that Applicants' PJM East nuclear capacity is decommissioned, derated or sold, and to the extent that new transmission capacity is constructed into PJM East that is not reflected in PJM's transmission expansion plan in the PJM Regional Transmission Report that is in effect as of June 2005.[12]

The virtual divestiture will eliminate any Competitive Analysis Screen failures during off-peak periods[13] and will eliminate any increased incentives that the merged company theoretically would have to economically or physically withhold non-nuclear generation arising from retained ownership of the nuclear facilities underlying the virtual divestiture.

There is ample Commission precedent that generation divestiture is an acceptable form of mitigation. While there is no similar precedent for the virtual divestiture, virtual divesture has all of the key elements necessary to make it an adequate alternative to physical divestiture. Further, while both the Commission and the antitrust agencies have expressed a clear preference for mitigation in the form of a permanent structural change (*e.g.*, divestiture), in this instance the virtual divestiture of baseload nuclear capacity is an economic solution that achieves the same effect without undercutting the operational efficiencies expected to be achieved by combined ownership of the nuclear units. Indeed, increasing nuclear output will have a small but significant tendency to lower wholesale

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12 As the Commission found in *Oklahoma Gas and Electric Company and NRG McClain LLC* (Docket No. EC03-131-000), transmission enhancements that restore the amount of competing supply to pre-acquisition levels are an appropriate structural remedy for acquisitions that fail the horizontal market power screen.

13 The results of the Competitive Analysis Screen are discussed in detail below.

prices. This is because increasing the amount of energy at "the bottom of the stack" will in at least some hours lower the PJM marginal cost. All else being equal, therefore, this should lower LMP (*i.e.*, Locational Marginal Price) prices, particularly in PJM East.

From the perspective of the Competitive Analysis Screen, the generation previously attributed to Applicants properly is attributed to parties winning the auction because it is the buyer, not the seller, that would determine to whom and where the energy is sold. The virtual divestiture – because of its firm delivery obligation – will eliminate Applicants' ability to withhold this nuclear energy from the market. Further, as noted earlier, the Commission already has recognized the sharply reduced ability or incentive to withhold nuclear energy from the market.

Importantly, the virtual divestiture also eliminates Applicants' potential increase in incentive to withhold other generation; that is, it eliminates Applicants' ability to benefit financially through higher market prices with respect to the virtually divested capacity to the same extent as if that generation had been physically divested. Therefore, the virtual divestiture has the desired effect of eliminating any increase in the merged firm's ability or incentive to withhold capacity from the market relating to the merging of the baseload generation.

The Baseload Auction is likely to increase the competitiveness of the PJM energy market, by making substantial amounts of baseload energy available to a number of market participants in essentially atomistic quantities. The fact that the baseload auctions coincide with the New Jersey BGS auction further enhances its attractiveness as mitigation. Other areas in PJM East, including Pennsylvania, also can benefit by increased access to competitive supplies in PJM East, both for suppliers currently serving retail choice customers and in the future as PECO's rate cap period ends. The Long-Term Contract, while perhaps not leading to as large a number of market participants, nevertheless increases the number of potential suppliers as compared to the pre-merger situation, and provides provide an opportunity for bidders for retail supply to access substantial amounts of baseload energy, including through a swap with Applicants for similar products in a non-PJM market.

Coal, Mid-Merit and Peaking Divestiture. Applicants have committed to divest 2,900 MW of coal, mid-merit, and peaking generation in PJM East. The divestiture of this generation (together with the virtual divestiture of nuclear energy) will eliminate any Competitive Analysis Screen failures during mid- and peak periods, and will eliminate any increased ability that the merged company theoretically would have to economically or physically withhold generation. No more than half of the divested capacity will be sold to any single purchaser and none of the capacity will be sold to any purchaser that currently owns more than 5 percent of the installed generating capacity in either PJM East or Expanded PJM. Any buyers with market shares between 3 and 5 percent will not be permitted to buy more than 25 percent of the divested capacity collectively (e.g., if one buys 25 percent none of the others in the 3 to 5 percent range can buy any of the capacity).[14] Applicants are requesting a period of up to 18 months from the date of closing to accomplish the divestiture, including all necessary regulatory approvals, but intend to accomplish the divestiture as soon as is commercially reasonable. The proposed interim mitigation gives them an incentive to do so.

Thus, in total Applicants intend to divest (through a combination of virtual and physical divestiture) the equivalent of 5,500 MW. As the delivered price analysis will demonstrate, this eliminates all of the screen failures in the PJM East market, as well as in the larger geographic markets that merit analysis. Table 2 below summarizes the delivered price test analysis for the PJM East market, reflecting the mitigation that Applicants have proposed.[15] As it shows, there are no screen failures in any time period and the markets remain only moderately concentrated.

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[14] The delivered price analysis assumes that the non-nuclear generation is divested to two parties that meet this 5 percent threshold. The analysis approximates the effect of selling to the eligible buyers. The delivered price analysis assumes that the nuclear generation is divested to two parties that do not currently own capacity in PJM.

[15] The table shows the Applicants' respective market shares, market size and concentration pre-merger; their post-merger market share and HHI change pre-mitigation; the amount of nuclear and other generation to be divested (virtual or otherwise); and Applicants' market share, market concentration and HHI change post-mitigation. Finally, the table shows the MW summer-equivalent of the energy divested. Corresponding tables, included *infra*, reflect similar details for other markets.

Table 2: Economic Capacity Results, PJM East, Post-Mitigation

		Pre-Merger: Exelon		Pre-Merger: PSEG		Pre-Merger		Post-Merger: EEG		Post-Merger		Mitigation and Post-Mitigation Results					
Period	Price	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	MW	Mkt Share	HHI	HHI Chg	Mitigation MW	Nuclear	Mkt Share	HHI	HHI Chg	MW Summer
S_SP1	$250	6,961	18.3%	9,658	25.4%	38,040	1,298	16,620	43.7%	2,227	929	4,877	2,201	30.9%	1,329	31	5,300
S_SP2	$80	6,032	18.4%	7,757	23.7%	32,786	1,218	13,788	42.1%	2,088	870	3,947	2,201	30.0%	1,273	55	4,300
S_P	$55	5,122	21.3%	5,957	24.8%	24,011	1,327	11,079	46.1%	2,385	1,058	3,947	2,201	29.7%	1,236	(91)	4,300
S_OP	$25	4,887	30.7%	2,631	16.5%	15,919	1,477	7,518	47.2%	2,492	1,015	2,201	2,201	33.4%	1,473	(4)	2,400
W_SP	$80	6,417	19.3%	7,796	23.4%	33,333	1,228	14,213	42.6%	2,128	900	4,061	2,289	30.5%	1,291	63	4,300
W_P	$55	5,451	22.5%	5,770	23.8%	24,281	1,323	11,221	46.2%	2,390	1,067	4,061	2,289	29.5%	1,222	(101)	4,300
W_OP	$30	5,167	26.6%	3,594	18.5%	19,398	1,324	8,761	45.2%	2,311	987	2,833	2,289	30.6%	1,297	(27)	2,950
SH_SP	$65	4,896	20.4%	5,095	21.3%	23,958	1,187	9,991	41.7%	2,057	870	3,233	1,800	28.2%	1,181	(6)	4,300
SH_P	$45	4,675	26.0%	2,935	16.3%	17,988	1,257	7,610	42.3%	2,105	848	2,196	1,800	30.1%	1,287	30	2,950
SH_OP	$20	4,338	30.3%	2,051	14.3%	14,305	1,406	6,389	44.7%	2,276	870	1,800	1,800	32.1%	1,389	(17)	2,400

ICAP Mitigation. Applicants also have committed to eliminate any screen failures in PJM's capacity, *i.e.*, ICAP, market.[16] The divestiture of mid-merit and peaking generation significantly mitigates any concerns in the ICAP market arising from the merger. The remaining screen failures are attributed to the combination of baseload generation, since the virtual divestiture of nuclear energy is of energy only and does not include the sale of capacity rights. Applicants are prepared to fully mitigate any screen failures in the ICAP market. However, the geographic market for ICAP and the nature of the product are being reconsidered by PJM, with material changes from the current ICAP market structure likely to be known prior to consummation of the merger.[17] Applicants commit at this time to bid into the PJM annual Planning Year capacity auction at a zero price the lesser of their net ICAP position (as measured by their net Unforced Capacity Position in PJM) or 2,400 MW.[18] This commitment is conservatively based on the 5,300 MW required to cure screen failures in the PJM East ICAP market as defined herein,[19]

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16 PJM's capacity market currently is based on unforced capacity credits, *i.e.*, UCAP.

17 As of this time, PJM expects to file its new Resource Adequacy Mechanism (RAM, the ICAP replacement) proposal in March 2005, requesting Commission approval in time to begin forward auctions this fall. Based on current information, it appears that the first planning year for which locational features of the new RAM will be used is the 2007-8 planning period. If this schedule holds, the specifics of the RAM will be known well before this merger is approved. Indeed, Applicants may well have sold forward sufficient ICAP to moot any concerns about the effect of the transaction on competition in the capacity market. In the event that the structure of the new capacity markets is not known at the time of closing, Applicants commit to sell ICAP in parallel with the energy auction.

18 This commitment will be reduced *pari passu* to the extent that more than 2,900 MW are divested outright.

19 Since the market structure for ICAP is essentially identical to the market structure for energy during the summer super-peak period, any mitigation that cures screen failures in that period will also cure screen failures for

and will be subject to the same basis for reduction (*i.e.*, sale, closure or permanent derating of the facilities or transmission expansion) as the baseload energy mitigation. Applicants commit to make a compliance filing within 30 days after closing to adjust their ICAP mitigation proposal to conform to any changes in the PJM ICAP program.

Ancillary Services. The Commission's regulations identify additional relevant products as spinning reserves, non-spinning reserves and imbalance energy. PJM has no imbalance energy market separate from the energy market. It has a quick-start non-spinning reserve market that is combined with spinning reserves. Some of the capacity to be divested will have significant ancillary services capability, and the mitigation of energy markets also will cure screen failures in the spinning reserve market. Regulation is not an enumerated product in relevant Commission Orders. Analysis of regulation is difficult because what is in the market differs substantially over time, since the units that are economic for providing regulation are those that are closest to the system marginal price; hence, the units that provide regulation vary as the system price varies.[20] About half of Applicants' regulation-capable generation capacity consists of pumped storage units. Significantly, Applicants are far from being pivotal suppliers, and the relevant market for regulation (Mid-Atlantic) has been found to be competitive. Even if Applicants were to withhold all of their regulation capacity, there would be sufficient capacity from non-Applicants to meet the market's regulation requirement twice over. Thus, market power concerns are not present.

Interim Mitigation. The purpose of the interim mitigation is to eliminate any merger-related incentive to economically or physically withhold capacity prior to implementation of the long-term mitigation measures described previously. In essence, interim mitigation requires that an amount of energy and other products at least equal to the amount to be divested be 1) sold for periods intended to cover the pre-divestiture period,

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ICAP. Thus, the maximum necessary ICAP mitigation is expected to be no more than is required for energy, and, as discussed *infra*, actually is less than the energy requirement.

[20] Thus, an analysis of regulation should, at least in principle, look rather like an analysis of energy in that competitive units should be those that economically compete at various price levels.

2) sold in amounts such that Applicants no longer have any of the product available for sale in the relevant PJM market, or 3) offered into the relevant PJM market either at a price of zero or at variable cost.

Baseload Energy. Within 90 days following the month in which the merger is closed, Applicants will auction an interim product identical to the Baseload Auction described above, except that 1) it will be for a shorter term, coinciding with the products commonly traded in PJM and 2) delivery will be either at the PJM East nuclear generation aggregate bus or at the PJM West Hub combined with a basis differential. The alternative delivery arrangement reflects the fact that the PJM West Hub is more liquid than PJM East, thereby facilitating the quick implementation of the interim mitigation. Market participants in PJM East should be financially indifferent as between the two products. Prior to the completion of the interim auction, Applicants commit to bid all of their PJM East nuclear capacity into the PJM day-ahead market at a zero price.

Coal, Intermediate and Peaking Energy. Within 30 days following the end of the month in which the merger closes, Applicants will sell the rights to 2,900 MW of energy and capacity from designated units that are included as candidates for divestiture. Under unit firm interim contracts, no more than half of the 2,900 MW will be sold to the same party, and the contracts will be in effect for no longer than 18 months from merger closing. If a designated unit is subsequently divested, the interim contract will be assignable without consent to the party acquiring the designated unit. The counterparty will acquire full dispatch and unit offering rights for the PJM energy and ancillary services markets, and all of the Unforced Capacity associated with the particular unit.[21] Until such time as the entire 2,900 MW of this capacity is committed under interim mitigation contracts, Applicants will bid 2,900 into the PJM day-ahead (and, if not dispatched, into the PJM real-time) market at a price not to exceed the equivalent of PJM

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21 Because more units may be offered for sale than are required to meet screen failures, the interim mitigation requirement is limited to the maximum required divestiture quantity. Units from which unit power sales will be offered will be from a subset of the offered units that have variable cost characteristics necessary to cure screen failures in all periods.

cost-capped rates (*i.e.*, variable cost defined in PJM's Cost Development Task Force rules plus 10 percent).

Ancillary Services. The interim mitigation contracts for the sale of coal, mid-merit and peaking energy are expected to mitigate the merger-related screen failures for spinning reserves associated with such generation. As noted earlier, there are no market power concerns relating to regulation. Nuclear generation has no ancillary services capability.

UCAP. Prior to Applicants' participation in the annual capacity auctions, Applicants have committed to bid into the PJM monthly auction at a price of zero the lesser of their ICAP mitigation amount (5,300 MW minus the amount of any capacity sales or interim mitigation unit sales) or their net PJM Unforced Capacity Position. This commitment is conservatively premised on the required ICAP divestiture in PJM East, even though locational ICAP markets are not expected to be in effect during the period of interim mitigation.[22]

That there will be no competitive harm in wholesale markets is also important from a retail perspective. 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. Further, while not directly relevant to the Commission's approval of this transaction, it is notable that the merger also will not eliminate any competitor in retail markets. Only Exelon has a retail marketing affiliate, and it is not active in PJM East. PSEG has no retail marketing affiliates and, thus, no retail supplier is eliminated as a result of the merger.

The merger raises no horizontal issues in non-PJM markets. While the merging parties each own or control affiliated generation outside of PJM, the extent of the generation controlled in markets where both own generation is *de minimis*.

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[22] The conservative nature of this commitment is illustrated by the fact that Exelon has no net ICAP in expanded PJM, the market definition applicable to the 2005-6 time period. Hence, no interim mitigation for that period should be required.

The merger also creates no material vertical market power issues. There are no issues related either to transmission ownership and operation, or to the combination of electric generation assets and fuels supplies or fuels delivery systems. The PECO, ComEd and PSE&G electric transmission systems are controlled by PJM. None of the utilities owns any interstate gas transmission pipelines and their intrastate systems are modest in scope. PECO operates a gas distribution system in four counties that surround, but do not include, the city of Philadelphia. Its gas service area includes several independent gas-fired generators, all but a few of which have bypassed the distribution system. PECO provides gas distribution service to only three unaffiliated electric generators totaling less than 200 MW. These are primarily either industrial facilities that consume the bulk of their electricity on-site or facilities that use natural gas as a secondary fuel. PECO provides gas transportation services to two affiliated generators at a negotiated discounted transportation rate.

PSE&G operates a gas distribution system in New Jersey that serves eight current or former qualifying facilities ("QFs") under contract with the utility, as well as two merchant generators: the Tosco plant (172 MW) and the Williams Red Oak plant (765 MW). These generating facilities served by PSE&G are under long-term gas distribution contracts or discounted tariffs PSE&G also provides gas transportation services to affiliated generators in its service area.

The mere ownership of LDC operations does not give rise to a concern that Applicants will use control over their gas LDCs to favor affiliated activities. Nor do they have the ability to use these systems to raise rivals' costs or otherwise disadvantage rivals. Distribution tariffs are regulated by the respective state public utility commissions, which have imposed open-access distribution requirements similar to those required by this Commission. Distribution tariffs are frequently constrained by bypass alternatives or existing long-term (sometimes discounted) contracts. It is unlikely and unnecessary that new generation would seek to be connected to an LDC as opposed to direct interconnection with a pipeline system. Newly built gas-fired generating facilities could readily avoid PECO's or PSE&G's service area or connect directly to one of the several interstate pipelines serving Pennsylvania and New Jersey.

Both PECO and PSE&G have firm transmission rights on the gas pipelines serving PJM in order to serve their gas distribution customers as well as their own gas-fired generating plants.[23] PECO's firm transportation rights are fully committed to meet retail customer load. Moreover, Applicants cannot withhold these transportation rights to reduce supply since 1) they are held to meet the needs of retail and requirements gas customers and 2) failure to use rights simply increases the amount of release and non-firm capacity available to competitors. Finally, both Pennsylvania and New Jersey have in place codes of conduct between gas and electric affiliates, and Applicants are in compliance with FERC Order No. 2004.

Part 33.4 of the Commission's regulations specifies the analysis to be performed for vertical mergers. The end result is that both the upstream and downstream markets need to be highly concentrated in order for there to be a potential vertical market power issue. Attributing gas-fired generation to the fuels transport supplier, as specified in Part 33.4, changes the result only to the extent the divested gas-fired units remain attributed to Applicants. After mitigation of the effects of this merger, the downstream markets in PJM Pre-2004 and Expanded PJM are not highly concentrated, as shown *infra*. In PJM East, this results in a highly concentrated market.[24] In the summer and winter periods, the HHI post-mitigation is in excess of 1,800 points, but below 2,000 points.[25] Since the downstream market for PJM East is highly concentrated under this methodology (with the attribution of gas-fired generation to the supplying gas transmission system or distribution company called for in Part 33.4), I also examined concentration in the

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23 With respect to PSE&G, most of the firm transmission rights are held by PSEG Energy Resources & Trading and the generation is owned by PSEG Fossil LLC. With respect to Exelon, most of the firm transmission rights are held by PECO and the generation is owned by Exelon Generation.

24 In other words, I only counted the divestiture of nuclear or coal units in my post-merger calculation. Of course, if some of the divested units are oil-fired, they too represent a reduction in Applicants' market share and would likely reduce concentration below 1800.

25 The fact that mitigation cures screen failures in the horizontal energy market analysis but not in the downstream vertical analysis (which also is the energy market) is because divested gas-fired generation still is attributed to Applicants in the latter analysis.

upstream market and determined that it, indeed, was not highly concentrated.[26] For the remaining relevant markets, PJM Pre-2004 and Expanded PJM, I did not perform an upstream analysis. However, based on my experience in performing upstream analyses, it is highly unlikely that these other upstream markets are highly concentrated because, particularly in markets with gas retail access, the ownership of firm transportation rights tends to be fragmented and mostly unconcentrated or, at worst, moderately concentrated. In any event, competitive conditions in the relevant PJM markets I examined are not conducive to a successful strategy of foreclosure or raising rivals' costs.

There are no other barriers to entry that raise concerns: Applicants do not have dominant control over generating sites and there has been substantial entry into relevant markets.

In short, none of the vertical concerns that the Commission focused upon in prior vertical mergers exist in this merger and the transaction does not create or enhance vertical market power.

For all these reasons, I recommend that the Commission find that the transaction, as proposed, will not adversely affect competition and approve the merger.

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26 The Commission approved the El Paso-Coastal merger on the basis, among other things, of an analysis by the merging parties that demonstrated the upstream market for gas in PJM East was not highly concentrated. The analysis submitted in that docket showed the delivered gas market for PJM was moderately concentrated. *El Paso Energy Corporation and The Coastal Corporation* 92 FERC ¶ 61,076 (2000) . Any larger geographic market definition in PJM likely would result in an unconcentrated market.

II. DESCRIPTION OF THE PARTIES

Exelon, ComEd and PECO

Q. PLEASE DESCRIBE EXELON.

A. Exelon, a registered public utility holding company, is the parent corporation of PECO and ComEd formed as a result of a merger among PECO Energy, Unicom Corporation (the former parent company of ComEd), and Exelon.[27]

Exelon's three business segments are Energy Delivery, Generation and Enterprises.

Q. PLEASE DESCRIBE EXELON GENERATION.

A. Exelon Generation is a Pennsylvania public utility that owns and operates electric generating facilities and engages in wholesale power and energy marketing and trading operations in the United State pursuant to Commission-approved market rate authority. All of the ownership interests in Exelon Generation are indirectly held by Exelon. Exelon Generation, through its subsidiaries, owns or controls via long-term contract approximately 33,000 MW of generation, primarily in PJM (26,000 MW), Electric Reliability Council of Texas, Inc. ("ERCOT") (3,600 MW) and Southeastern Electric Reliability Council ("SERC") (1,800 MW), as well as smaller amounts in ISO New England Inc. ("ISO-NE"), and in the control areas of Illinois Power Co. ("IP") and Central and Southwest ("CSWS") (often referred to as AEP West). See Exhibit J-3.

AmerGen Energy Company, LLC ("AmerGen") is a wholly-owned subsidiary of Exelon Generation that owns three nuclear stations: Three Mile Island and Oyster Creek located in PJM, and Clinton, located in the IP control area. The megawatts for Exelon Generation listed previously include these nuclear generating plants.

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[27] *Commonwealth Edison Co. and PECO Energy Co.*, 91 FERC ¶ 61,036 (2000).

An affiliate of Exelon recently completed the sale to Dynegy, Inc. of its 50 percent indirect ownership interest in Sithe Energies, Inc. ("Sithe"), which owns generation assets located primarily in New York and mid-Atlantic markets.[28]

Q. PLEASE DESCRIBE EXELON'S ENERGY DELIVERY BUSINESS.

A. Exelon's energy delivery business consists of the regulated sale of electricity and distribution services by ComEd in northern Illinois and PECO in southeastern Pennsylvania (Philadelphia). It also is the passive owner of transmission assets controlled by PJM and regulated under the PJM tariff. In addition, PECO is involved in the regulated sale of natural gas and distribution services in the Pennsylvania counties surrounding Philadelphia.

Neither PECO nor ComEd owns generation, and each serves its customers' capacity and energy needs through PPAs with Exelon Generation. PECO currently has no requirements customers. ComEd has three partial or full requirements wholesale customers within its control area served under fixed price contracts through May 31, 2007: the cities of Naperville (full requirements), Batavia and St. Charles.[29]

The states of Pennsylvania and Illinois have retail access for electricity customers, and both PECO's and ComEd's customers have the right to choose competitive energy suppliers. The majority of retail customers in PECO's service territory continue to be served by PECO at distribution rates that are capped through December 31, 2006, and generation rates that are capped through December 31, 2010. The majority of retail customers in the ComEd service territory continue to be served by ComEd at bundled retail rates that are frozen through 2006.

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[28] This sale has been approved by the Commission. *Sithe Energies, Inc., Dynegy New York Holdings et al.*, 110 FERC ¶ 62,027 (2005).

[29] A fourth municipal utility, City of Rochelle, is supplied by ComEd's retail affiliate, Exelon Energy. In addition, there are three municipal customers within ComEd's service territory who obtain their requirements from other suppliers.

The Illinois Electric Service Customer Choice and Rate Relief Law of 1997 ("Restructuring Act") initiated the state's restructuring initiative. The law provided Illinois customers with the ability to choose their electricity supplier, mandated a 20 percent rate reduction for residential customers, imposed a rate freeze,[30] and defined the utility's residual POLR service obligation.

Illinois is facing the end of the Restructuring Act's transition period. The Illinois Commerce Commission ("ICC") has hosted a series of workshops to examine the future of the electric market in Illinois and to develop a proposal for the ICC to consider. The post-2006 framework proposal developed by the stakeholders and the ICC staff, and endorsed by the ICC, is a vertical tranche auction, which is similar in many respects to the New Jersey BGS auction. Exelon has endorsed the ICC's recommendations and is working to implement the recommendation.

Q. PLEASE DESCRIBE EXELON'S RETAIL COMPETITIVE ENERGY SUPPLY BUSINESS.

A. Exelon Energy Inc. ("Exelon Energy") is authorized to provide retail electric and gas services as an unregulated retail energy supplier in Illinois, Massachusetts, Michigan, New Jersey, Ohio, Pennsylvania and other areas in the Midwest and Northeast United States. However, Exelon Energy is primarily active in the Midwest, with virtually no activity in PJM East.[31]

PSEG, PSE&G and PSEG Power

Q. PLEASE DESCRIBE PSEG.

A. PSEG is an exempt public utility holding company under PUHCA with four principal direct wholly-owned subsidiaries: PSE&G, PSEG Power, PSEG Energy Holdings LLC ("PSEG Energy Holdings") and PSEG Services Corporation. The principal operating

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30 The initial rate freeze was through December 31, 2004; it was extended in 2004 through Dec. 31, 2006.

31 A gas retail affiliate, AllEnergy, was active in the east, but its operations are being wound down.

subsidiaries of PSEG Power are PSEG Fossil, PSEG Nuclear LLC ("PSEG Nuclear") and PSEG ER&T. The principal operating subsidiaries of PSEG Energy Holdings are PSEG Global LLC and PSEG Resources L.L.C.

PSEG Global is an independent power producer and distributor, which develops, owns and operates electric generation, transmission and distribution facilities in selected domestic and international markets. PSEG Resources is a passive investor in a number of leveraged leases in the generation business.[32] Since these are merely passive investments and involve no form of operational control (nor any beneficial interest), I have not considered these investments as relevant to my analysis.

Q. **PLEASE DESCRIBE PSE&G.**

A. PSE&G is a transmission and distribution utility for electricity and gas service in New Jersey, covering approximately 2,600 square miles running diagonally across New Jersey from Bergen County in the northeast to an area below the city of Camden in the southwest.

All electric and gas customers in New Jersey have the ability to choose an electric energy and/or gas supplier. PSE&G serves as the supplier of last resort for electric and gas customers within its service territory through the provision of Basic Generation Service ("BGS"). New Jersey's Electric Distribution Companies ("EDCs"), including PSE&G, began providing two types of BGS in August 2003: BGS-FP provides for smaller commercial and residential customers at seasonally-adjusted fixed prices. BGS-CIEP provides supply for larger customers at hourly market prices for a term of 12 months. The New Jersey Board of Public Utilities has approved auctions held by the EDCs each February to determine who will supply BGS to New Jersey's EDCs. PSE&G's BGS-FP-eligible load is approximately 8,500 MW.

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32 These investments are described in the Application. In addition, PSEG Power has a minority ownership interest in Merrill Creek Reservoir, which is jointly owned by several generation owners that rely on water from the facility. As with the leveraged leases, this ownership interest is not relevant to my analysis.

With respect to its gas distribution business, PSE&G has entered into a full requirements contract with PSEG ER&T its gas supply through 2007, with evergreen rights.

Q. PLEASE DESCRIBE PSEG POWER.

A. PSEG Power integrates its generating asset operations with its wholesale energy, fuel supply, energy trading and marketing and risk management function through its wholly-owned subsidiaries: PSEG Nuclear, which owns and operates nuclear generating stations; PSEG Fossil, which develops, owns and operates domestic fossil generating stations; and PSEG ER&T, which markets the capacity and production of its affiliated generating stations and manages the commodity price risks and market risks related to generation.

PSEG Power, through its subsidiaries, along with PSEG Global, owns or controls approximately 18,000 MW of North American generation, primarily in PJM (14,000 MW), as well some capacity in ISO-NE, in the New York ISO Independent System Operator ("NYISO"), in ERCOT and in the Western Electric Coordinating System ("WECC"), under the control of the California Independent System Operator ("CAISO").[33] See Exhibit J-3.

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[33] This includes generation expected to be on-line by 2006. Generation under construction includes a 761 MW combined cycle plant in the NYISO and the 1,220 MW Linden combined-cycle plant in PJM. Both of these facilities replace existing generation at the respective sites.

III. FRAMEWORK FOR THE ANALYSIS

Q. WHAT ARE THE GENERAL MARKET POWER ISSUES RAISED BY MERGER PROPOSALS?

A. Market power is the ability of a firm profitably to maintain prices above competitive levels for a significant period of time. Market power analysis of a merger proposal examines whether the merger would cause a material increase in the merging firms' market power or a significant reduction in the competitiveness of relevant markets. The focus is on the effects of the merger, which means that the merger analysis examines those business areas in which the merging firms are competitors. This is referred to as horizontal market power assessment. In most instances, a merger will not affect competition in markets in which the merging firms do not compete. In the context of the proposed merger, therefore, the focus is properly on those markets in which Exelon and PSEG are actual or potential competitors. The analysis is intended to measure the adverse impact, if any, of the elimination of a competitor as a result of the combination.

Potential vertical market effects of the merger relate to the merging firms' ability and incentives to use their market position over a product or service to affect competition in a related business or market. For example, vertical effects could result if the merger of two electric utilities created an opportunity and incentive to operate transmission in a manner that created market power for the generation activity of the merged company that did not exist previously. The Commission has identified market power as also arising from dominant control over potential generation sites or over fuels supplies and delivery systems. Such dominant control could undercut the presumption that long-run generation markets are competitive.

Q. WHAT ARE THE MAIN ELEMENTS IN DEVELOPING AN ANALYSIS OF MARKET POWER?

A. Understanding the competitive impact of a merger requires defining the relevant market (or markets) in which the merging firms participate. Participants in a relevant market include all suppliers, and in some instances potential suppliers, who can compete to supply the products produced by the merging parties and whose ability to do so diminishes the ability of the merging parties to increase prices. Hence, determining the scope of a market is fundamentally an analysis of the potential for competitors to respond to an attempted price increase. Typically, markets are defined in two dimensions: geographic and product. Thus, the relevant market is composed of companies that can supply a given product (or its close substitute) to customers in a given geographic area.

Horizontal Market Power Issues

Q. HOW HAS THE COMMISSION TYPICALLY EXAMINED PROPOSED MERGERS INVOLVING ELECTRIC UTILITIES?

A. In December 1996, the Commission issued Order No. 592,[34] the "Merger Policy Statement," which provides a detailed analytic framework for assessing the horizontal market power arising from electric utility mergers. This analytic framework is organized around a market concentration analysis. The Commission adopted the DOJ/FTC *Horizontal Merger Guidelines* for measuring market concentration levels by the Herfindahl-Hirschman Index ("HHI").[35] On November 15, 2000, the Commission issued its Revised Filing Requirements Under Part 33 of the Commission's Regulations,[36] which affirmed the screening approach to mergers consistent with the Appendix A analysis set

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[34] Order No. 592, FERC Stats and Regs. ¶ 31,044 (1996).

[35] To determine whether a proposed merger requires further investigation because of a potential for a significant anti-competitive impact, the DOJ and FTC consider the level of the HHI after the merger (the post-merger HHI) and the change in the HHI that results from the combination of the market shares of the merging entities. Markets with a post-merger HHI of less than 1000 are considered "unconcentrated." The DOJ and FTC generally consider mergers in such markets to have no anti-competitive impact. Markets with post-merger HHIs of 1000 to 1800 are considered "moderately concentrated." In those markets, mergers that result in an HHI change of 100 points or fewer are considered unlikely to have anti-competitive effects. Finally, post-merger HHIs of more than 1800 are considered to indicate "highly concentrated" markets. The *Guidelines* suggest that in these markets, mergers that increase the HHI by 50 points or fewer are unlikely to have a significant anti-competitive impact, while mergers that increase the HHI by more than 100 points are considered likely to reduce market competitiveness. (See U.S. Department of Justice and Federal Trade Commission, *Horizontal Merger Guidelines*, 1992 [amended 1997].)

[36] Order No. 642, Final Rule in Docket No. RM98-4-000, 18 CFR Part 33, 93 FERC ¶ 61,164 (2000) ("Revised Filing Requirements").

forth in the Merger Policy Statement, and codified the need to file a screen analysis and the exceptions therefrom.

Appendix A of the Merger Policy Statement, the Competitive Analysis Screen, specifies a "delivered *price*" *screening* test to measure Economic Capacity, defined as energy that can be delivered into a destination market at a delivered cost less than 105 percent of the destination market price. The screening test also provides for an analysis of Available Economic Capacity, defined as energy over and above that required to meet native load and other long-term obligations that meets the delivered price test.

If a proposed merger raises no market power concerns (*i.e.*, passes the Appendix A screen), the inquiry generally is terminated. Both the Merger Policy Statement and the Revised Filing Requirements accept that merger applications involving no overlap in relevant geographic markets do not require a screen analysis or filing of the data needed for the screen analysis.[37]

Q. WHAT PRODUCTS HAS THE COMMISSION GENERALLY CONSIDERED?

A. The Commission generally has been concerned with three relevant product markets: non-firm energy, short-term capacity (firm energy) and long-term capacity.[38] Both Economic

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[37] Order No. 592 (at 30,113) states: "...it will not be necessary for the merger applicants to perform the screen analysis or file the data needed for the screen analysis in cases where the merging firms do not have facilities or sell relevant products in common geographic markets. In these cases, the proposed merger will not have an adverse competitive impact (*i.e.*, there can be no increase in the applicants' market power unless they are selling relevant products in the same geographic markets) so there is no need for a detailed data analysis."

The Revised Filing Requirements state that an analysis need not be filed if the applicant "demonstrates that the merging entities do not currently conduct business in the same geographic markets or that the extent of the business transactions in the same geographic markets is *de minimis*."

[38] The market for long-term capacity generally does not need to be analyzed since the Commission has concluded as a generic matter that the potential for entry ensures that the long-term capacity market is competitive See *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Statutes and Regulations, ¶ 31,036 - 31,657 (1996). The presumption that long-term capacity markets are competitive can be overcome if the applicants have dominant control over power plant sites or fuels supplies and delivery systems. This exception is addressed below.

Capacity and Available Economic Capacity[39] are used as measures of energy. The Commission's current policy does not specify required analyses of capacity markets as such, likely because competitive conditions in the energy market in peak periods closely correlate with conditions in capacity markets. Nevertheless, I have analyzed the PJM Unforced Capacity Credit ("UCAP") market.

Under the Economic Capacity and Available Economic Capacity measures, capacity that is attributed to a market participant is that capacity controlled by it that can reach the destination market, taking transmission constraints and costs into account, at a price no higher than 105 percent of the destination market price. As described above, the two measures differ as to the treatment of capacity used to meet native load requirements. The Commission has determined that long-term capacity markets are presumed to be competitive, unless special factors exist that limit the ability of new generation to be sited or receive fuel.

Order No. 642 directs Applicants to analyze relevant ancillary services markets (specifically, reserves and imbalance energy[40]) "when the necessary data are available." As discussed below, I analyzed relevant ancillary services markets within the limits of the quantitative data available.

Q. HOW HAS THE COMMISSION ANALYZED GEOGRAPHIC MARKETS?

A. Traditionally, the Commission has defined the relevant geographic markets as centered on the applicants and on utilities directly interconnected with the applicants, referred to as first-tier utilities. Both Order No. 592 and the Revised Filing Requirements continue to

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[39] I note that evaluating Available Economic Capacity is quite difficult in the context of this merger, given the state of retail access in Pennsylvania, New Jersey and Illinois. While identifying Applicants' load commitments is relatively straightforward, it is virtually impossible to match generation and load commitments for most PJM utilities. Notwithstanding these difficulties, which are discussed in more detail below, I analyzed Available Economic Capacity.

[40] Because PJM does not require balanced schedules, it has no imbalance market separate and distinct from spot energy markets.

define the relevant geographic market in terms of first-tier destination markets.[41] Further, in a merger context, the Commission considers as potential additional destination markets other utilities that historically have been customers of the applicants.

This test is intended to be a conservative screen to determine whether further analysis of market power is necessary. If the Appendix A analysis shows that a company will not be able to exercise market power in its first-tier destination markets, it generally follows that the applicants will not have market power in more broadly defined and more geographically remote markets. The screen is the first step in determining whether there is a need for further investigation. If the screening test is not passed, leaving open the issue of whether the merger will create market power, the Commission invites applicants to propose mitigation remedies targeted to reduce potential anti-competitive effects to safe harbor levels. In the alternative, the Commission will undertake a proceeding to determine whether unmitigated market power concerns mean that the merger is contrary to the public interest.

While destination markets typically are defined as individual control areas, the Commission's practice has been to aggregate customers that have the same supply alternatives into a single destination market. This approach has been accepted in a number of merger filings in New York, PJM, and New England.

> To simplify the analysis, customers that have the same supply alternatives, as identified in the competitive analysis screen, can be aggregated into a single destination market. The Commission has accepted this approach in a number of merger filings. For example, in Atlantic City/Delmarva, the Commission found acceptable the treatment of PJM as a single destination market since customers in PJM trade largely with the same set of suppliers. The same is true of mergers occurring within the New England and New York ISOs (*e.g.*, ConEd/NU and CMP/NYSEG).[42] [footnote omitted]

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[41] Order No. 592 at 30,119.

[42] Revised Filing Requirements, ¶ 31,311 at 31,844-5, citing *Atlantic City Electric Company and Delmarva Power & Light Company,* 80 FERC ¶ 61,126 (1997); *Consolidated Edison Co., Inc. and Northeast Utilities* 91 FERC ¶ 61,225 (2000). To the extent there are internal transmission constraints within these markets, the Commission has considered smaller markets within these single control areas as potentially relevant.

As discussed below, in the context of this merger, the appropriate focus of the competitive analysis is on PJM, both overall and relevant sub-markets within PJM. As I will describe, the overlap of generation ownership in other geographic markets is *de minimis* and does not require a screen analysis.

Vertical Market Power Issues

Q. WHAT ARE THE POTENTIALLY RELEVANT VERTICAL MARKET POWER ISSUES?

A. In the Revised Filing Requirements, the Commission set out several vertical issues potentially arising from mergers with input suppliers. The principal issue identified is whether the merger may create or enhance the ability of the merged firm to exercise market power in downstream electricity markets by control over the supply of inputs used by rival producers of electricity. Three potential abuses have been identified: the upstream firm acts to raise rivals' costs or foreclose them from the market in order to increase prices received by the downstream affiliate; the upstream firm acts to facilitate collusion among downstream firms; or transactions between vertical affiliates are used to frustrate regulatory oversight of the cost/price relationship of prices charged by the downstream electricity supplier. The downstream products to be analyzed in a vertical analysis are the same as in the horizontal analysis.

With respect to the vertical analysis, the Commission proposes defining the downstream market in the same manner as in the horizontal analysis. For upstream markets, the relevant geographic market has not been defined by the Commission. In concept, it should include the area in which suppliers to generators competing in the downstream market are located. The Commission suggests in *Dominion*[43] that the market includes sellers that can provide competitive alternatives, such as those that can provide transportation capacity on terms comparable to those offered by the merging firm.

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[43] *Dominion Resources, Inc. and Consolidated Natural Gas Company*, 89 FERC ¶ 61,162 (1999).

Q. HOW DOES THE FRAMEWORK FOR ASSESSING VERTICAL MARKET POWER DIFFER FROM THE HORIZONTAL ANALYSIS FRAMEWORK?

A. For the vertical market power screen, the Commission's focus is on the structural competitiveness of downstream or upstream product markets, as measured by HHIs. The main difference from the horizontal analysis is that in the vertical analysis, the focus is not on the change in HHIs resulting from the merger, but on the structure of those markets where one merging party sells upstream products in a geographic market in which the other merging party sells downstream products.

Q. WHAT ARE THE VERTICAL ISSUES THAT THE COMMISSION HAS FOUND REQUIRE INVESTIGATION IN THE CONTEXT OF MERGERS BETWEEN ELECTRIC UTILITIES AND GAS TRANSPORTATION PROVIDERS?

A. The Commission has indicated that under some circumstances such mergers could give rise to vertical concerns. The Commission has expressed its concern in decisions addressing "convergence mergers" and in Order No. 642, that vertical mergers "may create or enhance the incentive and/or ability for the merged firm to adversely affect prices and output in the downstream electricity market and to discourage entry by new generators."[44] Potential market power arising from a merger between an electric utility and a gas pipeline is discussed by the Commission principally in Order No. 642 and Section 33.4 of the Revised Filing Requirements, and in its orders in *Enova*, *Dominion*, *Brooklyn Union Gas* and *Energy East*.[45]

As already noted, the main areas of Commission concern are: (1) the creation of incentives for the gas-related upstream activities to raise costs for rivals of the electricity generation affiliate; (2) the enhanced ability to facilitate coordination of pricing in upstream or downstream markets; and (3) the enhanced ability to evade regulation,

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[44] III FERC Stats. & Regs. Regs. Preambles, ¶31,111 at 31,904.

[45] See Enova Corporation and Pacific Enterprises, 79 FERC ¶ 61,372 (1997) ("Enova"); Dominion; Long Island Lighting Company, 80 FERC ¶ 61,035 (1997) ("Brooklyn Union Gas"); and Energy East Corporation and RGS Energy Group, Inc., 96 FERC ¶ 61, 322 (2001) ("Energy East").

primarily through self-dealing.[46] The Commission also has expressed concerns that (a) convergence mergers involving an upstream gas supplier serving the downstream merger partner, as well as competitors of that partner, could result in preferential terms of service; and (b) a pipeline serving electric generation could provide commercially valuable information to newly affiliated electricity generating or marketing operations. My analysis considers each of these concerns, however, I note that these concerns typically are far less substantial for mergers involving LDCs than for mergers involving ownership of an interstate pipeline.

Q. PLEASE ELABORATE ON WHAT IS MEANT BY RAISING RIVALS' COSTS.

A. Foreclosure, or raising rivals' costs, refers to a situation in which a vertically integrated firm withholds inputs produced in its upstream operations (*e.g.*, delivered gas) from rivals in the downstream (*e.g.*, electric generation) market in order to increase the costs of downstream rivals, thereby increasing downstream market prices and creating an opportunity for the integrated firm to achieve increased profits from its downstream operations. It also may refer to a situation in which the price charged to rivals can be profitably increased as a result of a merger with additional generating facilities (*e.g.*, the economics of discounted service are changed by the merger).

If the vertically integrated firm exercises market power in the upstream market after the merger, the costs to rivals in the downstream market could increase. However, if competitors in the downstream market have adequate alternatives to the upstream product, the merged firms cannot exercise market power. Moreover, if conditions in the upstream market are not conducive to the exercise of market power (*i.e.*, the upstream market is competitive), an attempt to raise rivals' cost will be unsuccessful. Similarly, if the upstream or downstream markets are sufficiently competitive, there should be no issue of anti-competitive coordination.

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46 Because none of the Applicants own regulated assets that take service from the other Applicant's LDC, the regulatory evasion concern is not present and I do not discuss it further.

Q. ARE THERE ANY OTHER RELEVANT PARAMETERS IN CONSIDERING VERTICAL ISSUES?

A. The Commission has stated that a necessary condition for a convergence merger to cause a vertical concern is that <u>both</u> the upstream and downstream markets are highly concentrated.[47] In other words, the screen is passed if the downstream (or upstream) market is not highly concentrated, irrespective of the degree of concentration of the upstream (or downstream) market. A proper analysis of the upstream market requires that the structure of control of transportation capacity be examined, which requires that control of the transportation capacity be allocated to holders of firm capacity rights on the relevant pipelines with any unsubscribed capacity allocated to the pipeline owner. In my experience, this allocation has invariably resulted in a not highly concentrated market. In the context of this merger, which does not involve ownership of natural gas pipelines *per se*, but merely control over shares of delivery capacity, the relevant focus is on Applicants' contractual rights to use the interstate pipeline delivery system into the relevant markets.

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[47] "[H]ighly concentrated upstream and downstream markets are necessary, but not sufficient, conditions for a vertical foreclosure strategy to be effective" Revised Filing Requirements, ¶ 31,311 at 31,911. "A vertical merger can create or enhance the incentive and ability of the merged firm to adversely affect electricity prices or output in the downstream market by raising rivals' input costs if market power could be exercised in both the upstream and downstream geographic markets." Order No. 642, *slip op*. at 79. This was confirmed in *Energy East*. ("Applicants correctly conclude that because they have shown that the downstream markets are not highly concentrated, there is no concern about foreclosure or raising rivals' costs in this case.") *Energy East, op. cit.*

IV. DESCRIPTION OF METHODOLOGY

Q. PLEASE SUMMARIZE THE METHODOLOGY THAT YOU USED TO ANALYZE THE COMPETITIVE EFFECTS OF THE MERGER.

A. I evaluated the competitive effects of the merger using the delivered price test outlined in Appendix A and the Revised Filing Requirements. I implemented this analysis using a proprietary CRA model called the "Competitive Analysis Screening Model" ("CASm"). The source and methodology for the data required to conduct the delivered price test in CASm are described in Exhibit J-4. A technical description of CASm is provided in Exhibit J-5.

Q. WHAT DESTINATION MARKETS DID YOU CONSIDER?

A. Consistent with the instructions in the Revised Filing Requirements, I identified the destination markets that could potentially be impacted by the merger. First, I will discuss relevant PJM markets. In analyzing the PJM market, the Commission historically has taken into consideration the predominant west-to-east energy flow and defined markets by the three high-voltage interfaces within PJM: West, Central and East.[48] See Exhibit J-6. The location of Applicants' generation in PJM is summarized in Table 3 below:

Table 3: Applicants' Generation in PJM

	Exelon (MW)	PSEG (MW)
PJM East	7,180	10,121
PJM Central	3,108	1,120
PJM West and Far West	714	776
PJM (ECAR)	-	1,946
PJM (MAIN)	15,340	-
Total PJM	26,341	13,963

[48] The PJM regions and related transmission limits are discussed in the Commission's Order in Docket No. ER97-3729-000, 86 FERC ¶ 61,248 (1999), and have been considered as relevant markets in a number of orders. The PJM sub-markets have included PJM East; PJM Central plus East; and PJM West plus Central plus East. PJM Central and PJM West are not typically considered as relevant markets.

I considered PJM East as the smallest relevant geographic market, for a number of reasons, including historical precedent, location of Applicants' generation, transmission constraints, and price separation. The Commission has, on numerous occasions examined PJM East as a relevant geographic market. As shown in the table above, the majority of PSEG's generation (approximately 10,000 MW) and a significant portion of Exelon's generation (approximately 7,000 MW) is located inside of the Eastern Interface of PJM. The PJM Market Monitoring Unit has studied constraints within PJM and identified 51 hours in 2002 and 203 hours in 2003 that were "congestion-event hours."[49] In 2004, the number of hours when the Eastern Interface was constrained increased to 275 hours.[50]

This is the smallest relevant market for an analysis of this transaction: although local congestion within the Eastern Interface may occur, for example within the PECO zone or within the PSE&G zone, only one of the merging parties owns generation within these smaller constrained areas.[51] Similarly, I have determined that it is not necessary to analyze other submarkets within PJM Pre-2004. PJM Central, PJM West and PJM Far West have not been considered separate markets; these are markets that separate from each other and from PJM East only when constraints in a west-to-east direction separate the markets. Moreover, the West and Central interfaces are congested substantially less frequently than the East interface.[52]

If, for example, the Northern PSEG zone were deemed a relevant market, Exelon owns no generation within that market and the only market share it would receive would be an allocation of the limited interface into the Northern PSEG zone. Since Applicants' plan

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49 *2003 State of the Market*, PJM Market Monitoring Unit, March 4, 2004, page 164. In this analysis, "[t]he constrained hour data...use the convention that if congestion occurs for 20 minutes or more in an hour, the hour is considered congested."

50 Based on data from the PJM website. I note that the number of hours when prices separate between interfaces or even within the Eastern constraint can be substantially greater than the reported hours of constraint.

51 The exception is the joint ownership of nuclear plants.

52 In 2004, PJM Central had only 63 congestion event hours, and PJM West only 78 hours.

to divest or auction a significant amount of generation in PJM East, including from the jointly owned nuclear units, any concerns in individual sub-zones are similarly mitigated.

I also considered PJM Pre-2004 (that is, the portion of PJM consisting of the original PJM members in MAAC plus Allegheny Energy) as a relevant market in the absence of internal constraints, for example, when PJM East is not binding. This, again, is consistent with historical precedent and with PJM studies that show significant constraints between this area and the rest of Expanded PJM.

I also considered Expanded PJM as a relevant geographic market, consistent with the fact that there is now a single energy market across PJM. While I am not aware that the Commission has analyzed an Expanded PJM market in the context of a merger or other Section 203 application, the Commission has considered (and accepted) this market definition in the context of Section 205 applications for market-based rates.[53] As a pragmatic matter, I have analyzed this market in anticipation of concerns that Exelon's generation in Northern Illinois, despite its remoteness from PSEG's generation, should be considered in assessing this merger. Further, Expanded PJM is a relevant market in the absence of significant internal constraints within PJM. As I noted earlier, I considered Dominion Virginia Power to be included in Expanded PJM, in anticipation of its integration well before 2006.

I analyzed each of these markets – PJM East, PJM Pre-2004 and Expanded PJM – to evaluate the impact of the merger on competition. I did not analyze any of PJM's first-tier markets (other than those in which Applicants own generation), because such an analysis will not provide any further insight into the impact of this merger. As is self-evident, the effect of the merger on more remote geographic markets necessarily will be less than its effect on the markets I have analyzed.

Finally, I considered whether there were any destination markets outside of PJM that were potentially relevant, given the location of other Applicant-affiliated generation. As

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[53] *Virginia Electric and Power Company*, 108 FERC ¶ 61,242 (2004); *Dayton Power & Light Company et al.*, 109 FERC ¶ 61,268 (2004).

shown in Table 4 below, Applicants each own generation in the ISO-NE and ERCOT markets; analysis of other markets in which one or the other Applicant controls no generation is unnecessary. As I discuss later in my testimony, in these markets the extent of overlapping operations is sufficiently *de minimis* that a complete Competitive Analysis Screen is not necessary to conclude that there are no competitive concerns resulting from the merger.

Table 4: Applicants' Generation Outside of PJM

NERC	RTO	Exelon (MW)	PSEG (MW)
NPCC	ISO-NE	630	967
NPCC	NYISO	-	761
WECC	CAISO	-	443
SPP	SPP	795	-
ERCOT	ERCOT	3,651	2,026
SERC		1,755	-
MAIN	MISO	713	-
Total, Non-PJM		6,714	4,197

Note: Exelon's total is adjusted to account for double-counting of a unit connected to both ERCOT and SERC.

Q. **WHAT TIME PERIODS DID YOU ANALYZE?**

A. For each relevant market, I examined ten time periods for both the Economic Capacity and Available Economic Capacity measures, selected to reflect a broad range of system conditions. Broadly, I evaluated hourly load data to aggregate similar hours. I defined periods within three seasons (Summer, Winter and Shoulder) to reflect the differences in unit availability, load and transmission capacity. Hours were first separated into seasons to reflect differences in generating availability and then further differentiated by load levels during each season.[54] For each season, hours were segmented into peak- and off-

[54] Appendix A requires applicants to evaluate the merger's impact on competition under different system conditions. For example, aggregating summer peak and shoulder peak conditions may mask important differences in unit availability and, therefore, a merger could potentially affect competition differently in these seasons. Thus, applicants are directed to evaluate enough sufficiently different conditions to show the merger's

peak periods.[55] The periods evaluated (and the designations used to refer to these periods in exhibits) are:

SUMMER (June-July-August)

Super Peak 1 (S_SP1):	Top load hour
Super Peak 2 (S_SP2):	Top 10% of peak load hours
Peak (S_P):	Remaining peak hours
Off-peak (S_OP):	All off-peak hours

WINTER (December-January-February)

Super Peak (W_SP):	Top 10% of peak load hours
Peak (W_P):	Remaining peak hours
Off-peak (W_OP):	All off-peak hours

SHOULDER (March-April-May-September-October-November)

Super Peak (SH_SP):	Top 10% of peak load hours
Peak (SH_P):	Remaining peak hours
Off-peak (SH_OP):	All off-peak hours

Q. WHAT "COMPETITIVE" PRICE LEVELS DID YOU ANALYZE?

A. For each destination market, I evaluated conditions assuming destination market prices ranging from $20/MWh in the Shoulder Off-Peak periods to $250/MWh in the Summer Super Peak period. In PJM, the effect of these prices is that during the lowest-priced off-peak periods in summer and winter, only nuclear generation passes the delivered price test. However, I note that during off-peak, overnight periods, coal is operated at minimum generation to ensure availability for the next day's peak hours. Often, coal is bid during these periods at below its marginal cost (or even zero) to ensure operation.

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impact across a range of system conditions. On the other hand, the DOJ/FTC *Horizontal Merger Guidelines* discuss the ability to "sustain" a price increase, and a finding that a structural test (like the HHI statistic) violates the safe harbor for some small subset of hours during the year may not be indicative of any market power problems.

[55] Peak and off-peak hours were defined according to NERC's definition, except that I did not consider Saturdays to be peak days. *See* ftp://www.nerc.com/pub/sys/all_updl/oc/opman/apdx1f.doc.

While the delivered price analysis does not reflect the coal units as economic during off-peak periods, the effect on the overall results of the Competitive Screen Analysis is not material, as the price levels reflect the full range of market conditions.[56]

In Order No. 642, the Commission indicated that sub-periods should be determined by load levels rather than by time periods. As discussed below, I analyzed each market at prices that range from the levels that would apply at the lowest load levels to those consistent with the highest load levels. These prices analyzed were selected based on a review of PJM market prices. I considered the frequency and distribution of market prices, irrespective of season, as well as the distribution of market prices based on the seasonal definitions used for modeling purposes. I took into consideration actual prices in relevant PJM markets during 2004,[57] fuel prices in 2004 and forecast fuel prices for the reference year of my analysis, 2006. This broad range of prices, in combination with the time periods, should be reflective of a sufficient range of system conditions such that a full effect of the merger is captured in the analysis.

Q. PLEASE DESCRIBE THE BASIC MODEL ARCHITECTURE YOU USED IN ANALYZING THIS MERGER.

A. I used CRA's proprietary model, CASm, to perform the analysis. CASm is a linear programming model developed specifically to perform the calculations required in undertaking the delivered price test. The model includes each potential supplier as a distinct "node" or area that is connected via a transportation (or "pipes") representation of the transmission network. Each link in the network has its own non-simultaneous limit and cost. Potential suppliers are allowed to use all economically and physically feasible links or paths to reach the destination market. In instances where more generation meets

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56 However, failing to reflect the actual bidding behavior of owners of coal-fired generation does significantly overstate Applicants' share of generation in these off-peak periods, particularly in the PJM Pre-2004 and Expanded PJM markets. Applicants have a disproportionately high share of nuclear generation and a disproportionately low share of coal-fired generation.

57 Although locational prices are obviously different throughout Expanded PJM, I nevertheless used a single set of prices for my analysis of all the relevant markets, since the prices cover a full range of possible price conditions, from $20/MWh to $250/MWh.

the economic element of the delivered price test (*e.g.*, 105 percent of the market price) than can actually be delivered on the transmission network, scarce transmission capacity is allocated based on the relative amount of economic generation that each party controls at a constrained interface.

Q. HOW DID YOU ALLOCATE LIMITED TRANSMISSION CAPACITY?

A. Appendix A notes that there are various methods for allocating transmission, and that applicants should support the method used.[58] I allocated transmission based on a prorata, "squeeze down" method based on relative ownership shares of capacity at a transmission interface, rather than on the basis of economics, which would allocate limited transmission first to the least expensive generation. The prorata "squeeze-down" method, so-named because it seeks to prorate capacity at each node, is the closest approximation to what the Commission applied in *FirstEnergy*[59] that is computationally feasible. Under this method, shares of available transmission are allocated at each interface, diluting the importance of distant capacity as it gets closer to the destination market. When there is economic supply (*i.e.*, having a delivered cost less than 105 percent of the destination market price) competing to get through a constrained transmission interface into a control area, the transmission capability is allocated to the suppliers in proportion to the amount of economic supply each supplier has outside the interface.

Shares on each transmission path are based on the shares of deliverable energy at the source node for the particular path being analyzed. The calculations start at the outside of a network, defined with the destination market as its center, and end at the destination market itself. A series of decision rules are required to accomplish this proration. The

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[58] See Order No. 592, ¶ 31,044 at 30,133: "In many cases, multiple suppliers could be subject to the same transmission path limitation to reach the same destination market and the sum of their economic generation capacity could exceed the transmission capability available to them. In these cases, the ATC must be allocated among the potential suppliers for analytic purposes. There are various methods for accomplishing this allocation. Applicants should support the method used."

[59] *Ohio Edison Company, et al.*, 80 FERC ¶ 61,039 at 61,107: "When there was more economic capacity (or available economic capacity) outside of a transmission interface than the unreserved capability would allow to be delivered into the destination market, the transmission capability was allocated to the suppliers in proportion to the amount of economic capacity each supplier had outside the interface."

purpose of these decision rules is limited to assigning a unique power flow direction to each link for any given destination market analysis. Once the links are given a direction, the complex network can be solved. CASm implements a series of rules to determine the direction of the path. The first rule (and the one expected to be applied most frequently) is based on the direction of the flow under an economic allocation of transmission capacity. Other options take into consideration the predominant flow on the line based on desired volume (the amount of economic capacity seeking to reach the destination market, the number of participants seeking to use a path in a particular direction, and the path direction that points toward the destination market).

The model proceeds to assign suppliers at each node a share equal to their maximum supply capability. At each node, "new" suppliers (those located at the node outside of the next interface) are given a share equal to their supply capability, and the shares of more distant suppliers (those who have had to pass through interfaces more remote from the destination market in order to reach the node) are scaled down to match the line capacity into the node. Ultimately, the shares at the destination market represent the prorated shares of Economic Capacity (or Available Economic Capacity) that is economically and physically feasible.

This is the same modeling architecture that I have used to analyze numerous previous mergers in testimony relied upon by the Commission. A summary of the transmission architecture used in analyzing the relevant PJM markets is included in Exhibit J-6. In my analysis, I treated MISO as a single exporting control area. However, I note that this treatment of MISO has no material effect on the results of the analysis because any such assumption is overridden by the simultaneous import limits.

Q. WHAT ASSUMPTIONS DID YOU MAKE ABOUT SIMULTANEOUS IMPORT CAPABILITY?

A. Analyzing each of the relevant PJM markets requires an assumption about simultaneous import limit ("SIL"). As shown in Exhibit J-6, for imports into PJM East, I assumed a SIL of 7,300 MW, based on a study conducted by PSEG's transmission engineering group.[60] When I analyzed the PJM East market, I assumed that generation in the rest of PJM Pre-2004 competed for the limited transmission. In other words, I did not "squeeze" generation from Far West to West to Central. This is consistent with the assumption that, although PJM East is a sometimes-constrained market, the remaining interfaces in PJM Pre-2004 are not often constrained or constrained at the same time as PJM East.

For imports into PJM Pre-2004, I used an SIL of 4,600 MW. No transmission study was conducted for this purpose. Instead, I based the 4,600 MW on the maximum level of imports in 2003 for the capacity market.[61] I presume the actual SIL for energy imports would be even greater, and hence this is a conservative measure of import capability into PJM Pre-2004. When analyzing the PJM East market, I used the 4,600 MW SIL to limit flows into PJM Pre-2004, and the 7,300 MW SIL to limit flows into PJM East.

Finally, for imports into Expanded PJM, I used an SIL of 7,500 MW. PJM studied simultaneous import capability into PJM for 2004 conditions that included the integration of all the new PJM members, including Dominion.[62] When analyzing the PJM East market, I assumed the 7,500 MW SIL limited flows into Expanded PJM, the 4,600 MW SIL limited flows into PJM Pre-2004, and the 7,300 MW SIL limited flows into PJM East. When analyzing the PJM Pre-2004 market, I assumed the 7,500 MW SIL was applied to flows into Expanded PJM, and then the 4,600 MW SIL was applied to flows into PJM Pre-2004.

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[60] This study was conducted using PJM's transmission models for summer 2006. Thus, these models are intended to reflect any transmission upgrades that PJM assumes will be in effect by the summer of 2006. The workpapers for this study are included in my workpapers, filed as Critical Energy Infrastructure Information ("CEII").

[61] *2003 State of the Market*, PJM Market Monitoring Unit, March 4, 2004, pages 123. "An average of 3,819 MW of capacity resources was imported into the PJM and an average of 1,664 MW was exported (delisted) for an average net import of 2,155 MW of capacity resources during the period. The maximum export (delist) was 2,457 MW, while the maximum import was 4,638 MW."

[62] "Simultaneous PJM Import Capability", Document prepared by System Operations Division – Transmission, September 8, 2004, and posted on OASIS. http://www.pjm.com/markets/market-integration/downloads/documentation/20040909-simultaneous-pjm-import-capability.pdf

Q. WHAT YEAR DID YOUR ANALYSIS COVER?

A. I analyze 2006 market conditions, consistent with the Order No. 642 requirement that the analysis be forward looking.

Even though my analysis approximates 2006 market conditions, the primary source of data on generation and transmission is current and recent historical data. Where appropriate, I adjusted relevant data to approximate 2006 conditions. As described in Exhibit J-4, this includes load and generation dispatch (*i.e.*, fuel) costs. With respect to new generation, I only included generation already under construction and expected to be on-line by 2006; I did not include any additional planned generation not yet under construction. With respect to retirements, I included only units already retired or already approved by PJM for retirement prior to 2006.

Q. HOW DO YOU ACCOUNT FOR LONG-TERM PURCHASES AND SALES?

A. In the past, I have treated long-term power arrangements as resulting in a transfer of ownership and control to the purchaser. Order No. 642 discusses two criteria for determining control: operational control (*i.e.*, "the party that has the authority to decide when generating resources are available for operation"),[63] and economic or beneficial interest (*i.e.*, "the party for whose economic benefit the…unit is operated").[64] In the

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[63] *Revised Filing Requirements*, Section 33.3(c)(4)(i)(A).

> Economic capacity means the amount of generating capacity owned or controlled by a potential supplier with variable costs low enough that energy from such capacity could be economically delivered to the destination market. Prior to applying the delivered price test, the generating capacity meeting this definition must be adjusted by subtracting capacity committed under long-term firm sales contracts and adding capacity acquired under long-term firm purchase contracts (*i.e.*, contracts with a remaining commitment of more than one year). <u>The capacity associated with any such adjustments must be attributed to the party that has authority to decide when generating resources are available for operation.</u> Other generating capacity may also be attributed to another supplier based on operational control criteria as deemed necessary, but the applicant must explain the reasons for doing so. (emphasis added)

[64] *Order No. 642*, footnote 39.

> The starting point for calculating economic capacity is the supplier's own generation capacity with low enough variable costs that energy can be delivered to a market (after paying all necessary transmission and ancillary service costs, including losses) at a price that is five percent or less above the pre-merger market price. Capacity must be decreased to reflect any portion committed

Revised Filing Requirements and in subsequent orders concerning market rate authority, the Commission has emphasized the first of these criteria.[65] For most purchases and sales, I am unable to determine whether the seller or buyer has control[66] and in those cases I assigned control to the buyer. I note, however, that the treatment of purchases and sales is inconsequential in terms of the results of my analysis, except with respect to Applicants' contracts.

Exelon Generation has several long-term (more than one-year) contracts of relevance for the output of various plants located in the former ComEd control area. Through mid-2011, Exelon Generation has contracts with affiliates of Dominion to purchase the output of two coal-fired plants (Kincaid and State Line) formerly owned by ComEd. In my analysis, I treated the entire output of these units as available to (and controlled by) Exelon Generation when economic. Exelon Generation also has a series of long-term PPAs for approximately 3,600 MW of supply from merchant generation, mostly peakers, located in the former ComEd control area.[67] Again, in my analysis, I treated these PPAs as if Exelon Generation controls the units.

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to long-term firm sales; and it must be increased to reflect any portion acquired by long-term firm purchases. In addition, any capacity under the operational control of a party other than the owner must be attributed to the party for whose economic benefit the related unit is operated. The result of these calculations is the supplier's "economic capacity." (Emphasis added)

65 In the context of the Commission's new, interim generation market power analysis in connection with market-based rates, the Commission focuses on operational control ("if an applicant has control over certain capacity such that the applicant can affect the ability of that capacity to reach the relevant market, then that capacity should be attributed to the applicant when performing the screens."). *AEP Power Marketing, Inc. et al.*, Order on Rehearing, 108 FERC ¶ 61,026 (2004), P 65.

66 This uncertainty arises both from ambiguity in the Commission's guidance and a lack of access to contract terms. A common example is a unit contingent contract (tolling or otherwise) in which the buyer has the right to nominate output from the unit. However, the seller controls whether the unit is made available (typically subject to penalties for non-availability). Moreover, if the buyer does not nominate the output, the seller frequently has the right to dispatch the plant for its own account. Given this mixture of circumstances, it is not wholly clear which party has "control" in the sense relevant to the Commission's market power tests.

67 Exelon Generation also has PPAs or tolling agreements for the output of generation outside of PJM that I considered under its control as well. See Exhibit J-3.

Additionally Exelon Generation has a long-term contract with Illinois Power to sell 400 MW of the output of the Clinton nuclear unit located in the Illinois Power control area through 2006, which I reflected in my analysis as under the control of the buyer.

With respect to purchases from QFs or non-utility generators ("NUGs"), I included as Exelon-affiliated generation purchases totaling less than 200 MW from several NUGs, and treated them as must-take, non-dispatchable. However, because of regulatory treatment, PSE&G does not control its NUGs. PSE&G sells the energy delivered and capacity provided under NUG contracts to PJM. PSE&G has no financial interest in the price received for this power. Thus, PSE&G does not have either operational control of or beneficial interest in these NUGs. These NUGS were treated in my modeling as must-take, non-dispatchable units, but unaffiliated with Applicants.

PSEG has sold a substantial amount of energy (as well as capacity) in the New Jersey BGS auction, as well as through long-term bilateral sales. I conservatively have not taken these into account in my analysis of Economic Capacity, but have reflected them in my analysis of Available Economic Capacity.

Finally, both Exelon Generation and PSEG ER&T have contracts to sell capacity (ICAP/UCAP) in the PJM market. I have not taken these into account in either my energy or capacity analyses.

Q. PLEASE DESCRIBE YOUR BASE, PRE-MERGER CASE WITH RESPECT TO EXELON.

A. As shown in Table 5 below, Exelon Generation's owned and contracted resources in PJM Pre-2004 total 11,002 MW, mostly located in PJM East,[68] which is equivalent to Exelon's Economic Capacity within the PJM Pre-2004 market at the highest-priced time period, before adjustment for outages (and before consideration of imports).

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[68] This tabulation reflects energy only, and does not include purchases or sales of capacity. Also, these figures will differ slightly from those used in my capacity analysis, primarily because of differences in the treatment of NUGs and other generation that does not typically qualify as capacity.

PECO's forecasted load requirement for 2006 is 8,033 MW. Thus, Exelon's "excess" supply in PJM Pre-2004 (before consideration of reserves) is less than 3,000 MW, which is equivalent to Exelon's Available Economic Capacity within the PJM Pre-2004 market at times of peak (again, before adjustment for outages). In analyzing Available Economic Capacity, I assume that PECO's load in the East was served by its generation in both PJM East and the rest of PJM Pre-2004. Consistent with Order No. 592, I assumed that the "lowest running cost units are used to serve native load."[69]

ComEd will continue to have POLR load obligations through 2006, and, indeed is currently capacity-short with respect to these obligations, as shown in Table 5 below.

Table 5: Exelon Generation and Load in PJM

Exelon Generation and Load (in megawatts)	**PJM East**	**Rest of PJM Pre-2004**	**PJM Pre-2004**	**Rest of Expanded PJM**
Economic Capacity Exelon Generation Owned and Contracted-For Resources	7,180	3,822	11,002	15,340
Peak Load, 2006	8,033	0	8,033	18,000
Available Economic Capacity	NA	NA	2,969	(2,660)

Table 6 below reflects Exelon's net position in the ICAP market in 2006. However, the ICAP analysis I undertake later is based on Exelon's gross, rather than net, ICAP position.

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69 Order No. 592, *slip op*, page 70. I note that this section continues, and states: "As competition develops, this presumption may not be valid." The following footnote is included: "For example, in a market with full retail access and a bid-based power exchange, all generation units would be in the market." However, in the specific circumstances for PECO, even in a full retail access environment and a bid-based power exchange, PECO has the obligation to serve its native load customers through 2010.

Table 6: Exelon ICAP Position

Exelon Generation and Load (in megawatts)	**PJM Pre-2004**	**Rest of Expanded PJM**
Starting ICAP Position (see Table 5)	2,969	(2,660)
Plus Purchases, Jun '05-May '06	0	1,700
Minus Sales, Jun '05-May '06	0	1,000
Net ICAP Position, Jun '05-May '06		(1,960)
Plus Purchases, Jun '06-May '07	0	500
Minus Sales, Jun '06-May '07	0	1,000
Net ICAP Position, Jun '06-May '07	2,969	(3,160)

Q. **PLEASE DESCRIBE YOUR BASE CASE ASSUMPTIONS WITH RESPECT TO PSEG.**

A. As shown in Table 7 below, PSEG's owned and contracted resources in PJM Pre-2004 total 12,017 MW, mostly located in PJM East. PSE&G has no POLR load obligations as such, since its POLR responsibilities are met through the New Jersey BGS auction.

Table 7: PSEG Generation and Load

PSEG Generation and Load (in megawatts)	**PJM East**	**Rest of PJM Pre-2004**	**PJM Pre-2004**	**Rest of Expanded PJM**
Economic Capacity PSEG Generation Owned and Contracted-For Resources	10,121	1,896	12,017	1,946
PSE&G Load Responsibility, 2006	0	0	0	0
Load Commitments, Jun '05-May '06			4,975	0
Available Economic Capacity, Jun '05-May '06			7,042	1,946
Load Commitments, Jun '06-May '07			2,200	
Available Economic Capacity, Jun '06-May '07			9,817	1,946

However, PSEG is a supplier into the BGS auction, and provides the supply for 42 tranches for the period June 2005 through May 2006 and 17 tranches for the period June 2006 through May 2007. Each tranche entails the requirement to supply approximately 100 MW of peak load obligation (capacity, energy and ancillary services), with the delivery requirement following the shape of the 100 MW of peak load. The peak load could be slightly higher or lower depending on customer migration and load growth. PSEG also has a commitment to serve 275 MW of Duquesne POLR obligations (capacity, energy and ancillary services) through May 2006, and a commitment to provide 500 MW of firm energy to FirstEnergy for delivery at PJM West through 2008. For purposes of analyzing Available Economic Capacity, I reflect PSEG's commitment to serve 4,975 MW of load through May 2006 (4,200 MW BGS, plus 275 MW Duquesne, plus 500 MW FirstEnergy) and 2,200 MW of load for the remainder of 2006 (1,700 MW BGS plus 500 MW FirstEnergy), as shown in Table 7 above.[70]

Table 8 below reflects PSEG's net position in the ICAP market. As with Exelon, the ICAP analysis I undertake later is based on PSEG's gross, rather than net, ICAP position.

Table 8: PSEG ICAP Position

PSEG Generation and Load (in megawatts)	PJM Pre-2004	Rest of Expanded PJM
Starting ICAP Position (see Table 7) Jun '05-May '06	7,042	1,946
Plus Purchases, Jun '05-May '06	0	0
Minus Sales, Jun '05-May '06	2,400	0
Net ICAP Position, Jun '05-May '06	4,642	1,946
Starting ICAP Position (see Table 7) Jun '06-May '07	9,817	1,946
Plus Purchases, Jun '06-May '07	0	0
Minus Sales, Jun '06-May '07	2,100	0
Net ICAP Position, Jun '06-May '07	7,717	1,946

70 PSEG also has commitments to provide approximately 150 MW to retail aggregators. I conservatively did not include this in my analysis.

V. IMPACT OF THE MERGER ON COMPETITION

Q. WHAT SPECIFIC ANALYSES DID YOU CONDUCT TO EVALUATE THE POTENTIAL COMPETITIVE EFFECTS ARISING FROM THE COMBINATION OF GENERATION ASSETS?

A. Consistent with the guidance in the *Merger Policy Statement*, I analyzed Economic Capacity and Available Economic Capacity, and ancillary services markets. I also analyzed the PJM market for capacity. As discussed earlier, I examined PJM East, PJM Pre-2004, and Expanded PJM as relevant destination markets. I also considered other geographic markets in which Applicants own generation outside of PJM.

In the sections below, I first look at each of the PJM markets for Economic Capacity. Second, I consider the relevant Available Economic Capacity analyses. Third, I evaluate any other relevant geographic markets. Fourth, I evaluate capacity and ancillary services markets in PJM. Finally, I present the results of the analysis of mitigation and the effect on the Competitive Analysis Screen.

PJM Markets: Economic Capacity

Q. WHAT DID YOUR ANALYSIS SHOW FOR ECONOMIC CAPACITY IN PJM EAST?

A. The Economic Capacity analysis reflects the substantial overlap of generation owned by the Applicants in PJM East.[71] In this market, the Competitive Analysis Screen is failed in all time periods, as shown below in Table 9 and in Exhibit J-7. Pre-Merger, Exelon's market share ranges from 18 to 31 percent, and PSEG's from 14 to 25 percent. The market is highly concentrated post-merger, with a combined market share as high as 47 percent and HHI changes in excess of 1,000 points.

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[71] The analyses also reflect the allocation of a portion of the interface into PJM East to Applicants' generation located in the rest of PJM.

Table 9: Economic Capacity, PJM East

		Pre-Merger						Post-Merger			
		Exelon		PSEG				EEG			
Period	Price	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	MW	Mkt Share	HHI	HHI Chg
S_SP1	$250	6,961	18.3%	9,658	25.4%	38,040	1,298	16,620	43.7%	2,227	929
S_SP2	$80	6,032	18.4%	7,757	23.7%	32,786	1,218	13,788	42.1%	2,088	870
S_P	$55	5,122	21.3%	5,957	24.8%	24,011	1,327	11,079	46.1%	2,385	1,058
S_OP	$25	4,887	30.7%	2,631	16.5%	15,919	1,477	7,518	47.2%	2,492	1,015
W_SP	$80	6,417	19.3%	7,796	23.4%	33,333	1,228	14,213	42.6%	2,128	900
W_P	$55	5,451	22.5%	5,770	23.8%	24,281	1,323	11,221	46.2%	2,390	1,067
W_OP	$30	5,167	26.6%	3,594	18.5%	19,398	1,324	8,761	45.2%	2,311	987
SH_SP	$65	4,896	20.4%	5,095	21.3%	23,958	1,187	9,991	41.7%	2,057	870
SH_P	$45	4,675	26.0%	2,935	16.3%	17,988	1,257	7,610	42.3%	2,105	848
SH_OP	$20	4,338	30.3%	2,051	14.3%	14,305	1,406	6,389	44.7%	2,276	870

Q. **WHAT DID YOUR ANALYSIS SHOW FOR ECONOMIC CAPACITY IN PJM PRE-2004?**

A. Market shares and HHI changes are significantly lower in PJM Pre-2004, but the Competitive Analysis Screen still is failed in all time periods, as shown below in Table 10 and in Exhibit J-7. Pre-merger, Exelon's market share ranges from about 14 to 26 percent, and PSEG's from about 10 to 15 percent. The market is moderately concentrated post-merger in all time periods, with HHI changes ranging from about 350 to 650 points.

Table 10: Economic Capacity, PJM Pre-2004

		Pre-Merger						Post-Merger			
		Exelon		PSEG				EEG			
Period	Price	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	MW	Mkt Share	HHI	HHI Chg
S_SP1	$250	10,508	13.6%	11,210	14.5%	77,273	896	21,718	28.1%	1,291	395
S_SP2	$80	9,545	13.8%	9,288	13.4%	69,380	885	18,834	27.2%	1,254	369
S_P	$55	7,976	14.6%	7,455	13.7%	54,517	971	15,431	28.3%	1,371	400
S_OP	$25	6,416	25.9%	3,189	12.9%	24,749	1,217	9,605	38.8%	1,885	668
W_SP	$80	9,899	14.1%	9,334	13.3%	70,238	883	19,233	27.4%	1,257	374
W_P	$55	8,299	15.1%	7,273	13.2%	54,932	968	15,571	28.4%	1,368	400
W_OP	$30	7,701	17.7%	4,946	11.4%	43,557	985	12,648	29.0%	1,386	401
SH_SP	$65	7,866	15.6%	6,263	12.4%	50,501	951	14,129	28.0%	1,337	386
SH_P	$45	6,936	17.2%	4,070	10.1%	40,251	1,004	11,006	27.3%	1,353	349
SH_OP	$20	5,472	26.4%	2,440	11.8%	20,715	1,206	7,912	38.2%	1,828	622

Q. WHAT DID YOUR ANALYSIS SHOW FOR ECONOMIC CAPACITY IN EXPANDED PJM?

A. While Exelon's market share in Expanded PJM is about the same as in PJM Pre-2004 (given the addition of its owned or controlled generation in the former ComEd control area), PSEG's market share is significantly smaller such that overall market shares and HHI changes are significantly lower in Expanded PJM. The Competitive Analysis Screen is failed in all time periods, as shown below in Table 11 and in Exhibit J-7. Pre-merger, Exelon's market share ranges from about 15 to 22 percent, and PSEG's from about 5 to 8 percent. The market is moderately concentrated post-merger, with HHI changes ranging from about 170 to about 250 points.

Table 11: Economic Capacity, Expanded PJM

		Pre-Merger						Post-Merger			
		Exelon		PSEG				EEG			
Period	Price	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	MW	Mkt Share	HHI	HHI Chg
S_SP1	$250	24,354	14.9%	12,929	7.9%	163,707	774	37,283	22.8%	1,009	235
S_SP2	$80	23,384	15.2%	11,006	7.1%	154,162	795	34,390	22.3%	1,011	216
S_P	$55	18,813	15.3%	9,153	7.5%	122,719	902	27,966	22.8%	1,130	228
S_OP	$25	16,950	22.3%	3,189	4.2%	76,038	1,447	20,139	26.5%	1,634	187
W_SP	$80	24,013	15.4%	11,053	7.1%	156,250	804	35,067	22.4%	1,021	217
W_P	$55	19,150	15.3%	8,973	7.2%	124,828	909	28,123	22.5%	1,130	221
W_OP	$30	18,373	17.8%	4,946	4.8%	102,979	1,102	23,319	22.6%	1,274	172
SH_SP	$65	19,460	16.4%	7,672	6.5%	118,586	850	27,133	22.9%	1,063	213
SH_P	$45	15,842	16.5%	5,462	5.7%	95,869	932	21,304	22.2%	1,120	188
SH_OP	$20	12,975	21.8%	2,440	4.1%	59,411	1,428	15,415	26.0%	1,608	180

PJM Markets: Available Economic Capacity

Q. HAVE YOU ALSO ANALYZED THE EFFECTS OF THE MERGER ON AVAILABLE ECONOMIC CAPACITY?

A. Yes, although I note that developing a comprehensive Available Economic Capacity analysis is quite difficult, given the status of retail access in PJM. Under conditions of full retail access, the Available Economic Capacity analysis becomes identical to Economic Capacity. However, despite full retail access in some portions of PJM (*e.g.*, Pennsylvania, New Jersey and Illinois), both Exelon and PSEG have continuing load obligations: PECO in the form of a requirement to provide POLR service to its customers through 2010 and PSEG in the form of load commitments secured as a participant in the New Jersey BGS auction. Thus, my analysis of Available Economic Capacity takes into consideration Applicants' commitments to serve customer loads. As described earlier, PECO's peak load commitments are forecast to be approximately 8,000 MW and PSEG's peak load commitments conservatively are assumed to conservatively be 2,200 MW.[72] ComEd also is assumed to have load consistent with its POLR commitments totaling approximately 18,000 MW.

Utilities in New Jersey, Maryland, Pennsylvania and elsewhere in the mid-Atlantic generally still have POLR responsibilities, but tend to serve load through PPAs or, as in the case of New Jersey, through the BGS auction that effectively results in the sale of load obligations to third-parties. Retail access also exists in other PJM states (*e.g.* Ohio) and in states from which power is exported to PJM. The real analytic difficulty arises because there are no publicly-available data identifying which generation is committed to serving load. The BGS auction, for example, reflects that the winning bidders include marketers, and it is impossible to determine from available data which generation they may have procured to serve the load or for what period. A further complication is that some of the retail load commitments that will be in effect in 2006 and beyond will be determined in procurements that have not yet occurred. For these reasons, I have not attempted to speculate on individual entities' load requirements.[73] Instead, I have looked at bounding the results with two separate analyses. First, I take into account only Applicants' load commitments (that is, ComEd's/PECO's and PSEG's commitments to serve load directly or as the winner in the BGS auctions, respectively). I also take into account the load obligations of AEP and Dominion, as both utilities continue to serve most of their load or default service obligations from owned generation. In this scenario, all other generation is assumed to be uncommitted. The second analysis, in addition to taking into account Applicants' load commitments (as well as AEP's and Dominion's), assumes that all other generation in the market was committed to the extent there existed

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[72] These peak load requirements are shaped to reflect the time period assumptions I described earlier.

[73] Elsewhere, the Commission has indicated its distaste for hypothetical assumptions about the extent of retail access in markets where such access has begun. *EME Homer City Generation, L.P.*, 86 FERC ¶ 61,016 (1999).

a load requirement somewhere in the market. For example, if the remaining generation in the market is 50,000 MW and the remaining load is 40,000 MW, only 10,000 MW of generation would count as Available Economic Capacity. Consistent with Appendix A of the Merger Policy Statement, I assumed, in this example, that the 40,000 MW of lowest variable cost generation was used to serve load, regardless of the actual party that had load responsibility or owned generation. In this scenario, I have not matched specific generation to specific load, but do measure remaining available market generation. This analysis shows the minimum amount of non-applicant Available Economic Capacity, since it assumes that all load is served from either owned generation or long-term contracts. In fact, some load doubtless is served from short-term contracts or spot purchases.

The HHIs in both of these analyses are somewhat suspect, and perhaps the proper focus is on the Applicants' total amount of Available Economic Capacity, rather than the HHIs and the HHI changes. However, this does not fully resolve the problem since one cannot calculate HHI change without a proper measure of the size of the market and, hence, Applicants' market share. For the Expanded PJM market, Applicants' mitigation commitment exceeds Applicants' Available Economic Capacity, but in other markets and time periods it does not. Of course, the proposed divestiture will substantially reduce Applicants' shares of Available Economic Capacity.

In any event, Available Economic Capacity is a questionable metric for defining market share in PJM. All capacity must be bid into the PJM market and selected to run before it can generate. Hence, irrespective of retail load commitments, all of a supplier's Economic Capacity is relevant to setting market prices. Thus, while I have presented an Available Economic Capacity analysis as required by the Commission's regulations, I have focused primarily on the Economic Capacity analysis in determining the effects of the merger on competition and in assessing the efficacy of mitigation.

Q. WHAT ARE THE RESULTS OF YOUR AVAILABLE ECONOMIC CAPACITY ANALYSES?

A. Exhibit J-8 presents a series of results for Available Economic Capacity. For PJM East, as shown on page 1, Exelon's Available Economic Capacity ranges from about 800 MW to about 2,400 MW, depending on the time period considered, and PSEG's ranges from about 400 MW to about 8,300 MW. Assuming no other generation in PJM East is committed to serving load, their combined shares of Available Economic Capacity range from 12 to 32 percent. The market is unconcentrated or moderately concentrated and the HHI changes are as high as about 400 points. However, after consideration of Applicants' mitigation plan, Applicants' market share is reduced to no more than about 17 percent and, in all instances, the transaction is deconcentrating.

For PJM Pre-2004 (page 2 of Exhibit J-8), the level of Applicants' Available Economic Capacity is higher than in PJM East, but assuming no other generation in PJM Pre-2004 is committed to serving load, their combined shares of Available Economic Capacity are no more than 21 percent. The market is unconcentrated to moderately concentrated before mitigation, and, once again, after consideration of Applicants' mitigation plan, the transaction is deconcentrating and Applicants' market share is reduced to no more than about 11 percent. Even with the highly conservative scenario in which the rest of PJM Pre-2004 load is assumed to be served from long-term entitlements to capacity (page 3 of Exhibit J-8), an assumption that is simply unrealistic, Applicant's mitigation plan results in the market being deconcentrated relative to the pre-merger scenario.

Finally, for Expanded PJM, where I take into consideration the load commitments of ComEd, Dominion and AEP, as well as PECO and PSE&G, as shown in page 4 of Exhibit J-8, Applicants' combined shares of Available Economic Capacity are no more than about 13 percent. The market is unconcentrated and the HHI changes pass the screening thresholds, even before mitigation.

Q. YOU STATED THAT YOU CONSIDERED WHETHER NORTHERN NEW JERSEY, OR THE NORTHERN PSEG ZONE, WAS A RELEVANT MARKET. PLEASE DESCRIBE YOUR ANALYSIS.

A. As I noted earlier, the Northern PSEG zone is not a relevant geographic market for purposes of the merger analysis because Exelon has no generation in that market. The merger will have no incremental effect on the ability or the incentive of the Applicants to influence prices in that market, other than the competitive effects of the merger on all of PJM East, which are resolved in the Applicants' mitigation proposal.

First, consider the effects of the merger on northern New Jersey when there are no binding constraints into that market. Under such circumstances, the geographic boundaries of this market are no smaller than all of PJM East, and the proposed mitigation for PJM East resolves any competitive effects.

Now consider the effects of the merger on northern New Jersey when constraints into that market are binding. EEG will have no more generation in the market than did PSEG before the merger. Thus, the incentive to raise prices in that market will be no greater after the merger, and will be reduced to the extent Applicants, pursuant to their mitigation plan, divest coal, mid-merit or peaking generation in northern New Jersey, because in either case the Applicants will have the same amount of, or less, generation that benefits from higher northern New Jersey prices.

The ability to raise prices in northern New Jersey also will not be increased after the merger. The amount of the Applicants' generation in the market will be the same or less after the merger, so there will be no additional ability to withhold generation from the market. The only change caused by the merger will be the fact that EEG will have more generation outside the market than PSEG had before the merger, but any generation that EEG might withhold outside the constrained market will not affect prices inside the constrained market. The only possible effect inside the northern New Jersey market of withholding a former Exelon unit located outside the market is that the mix of imports into northern New Jersey might change, but prices in the market will remain the same.

Hence, taking into consideration the mitigation plan in PJM East, the effect of withholding generation in northern New Jersey is no different than it would be without the merger and the effect of withholding Exelon (or former PSEG) generation elsewhere in PJM East also is no different than pre-merger.

Notwithstanding the clear fact that the merger cannot have a unique effect on northern New Jersey, a screen analysis limited to this area would show screen failures.[74] This is merely a by-product of how other generation in PJM East is "squeezed down" by the transmission limit into northern New Jersey. For the reasons discussed above, this does not reflect a market power problem, and no additional mitigation should be required. If the Commission determines, however, that additional mitigation is necessary, Applicants' would agree to mitigate the northern New Jersey screen failures. The screen failures would be eliminated by the divestiture of no more than 100 MW of coal-fired generation and no more than 100 MW of mid-merit generation. This is a subset of the 5,500 MW of overall mitigation. Applicants would agree to meet this requirement either by divesting such generation in northern New Jersey as part of their overall divestiture commitment or by delivering baseload energy into northern New Jersey (or selling it at Applicants' PJM East buses plus a basis differential into northern New Jersey). As with other divestitures, selling or delivering generation with a lower variable cost also mitigates the screen failure.

Other Relevant Markets

Q. ARE THERE OTHER MARKETS IN WHICH THERE IS AN OVERLAP IN APPLICANTS' GENERATION?

A. With two exceptions, Applicants either "do not currently operate in the same geographic markets or...the extent of the business transactions is *de minimis*"[75] and, therefore, no

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[74] This analysis is contained in my workpapers.

[75] Section 33(a)(2) of the Revised Filing Requirements. The Commission established an exemption from the requirement to file a horizontal Competitive Analysis Screen if the applicant:

further analysis is required. The following table was presented earlier in my testimony and also is included in Exhibit J-3. The discussion below examines each of the markets or regions in which Applicants own generation outside of PJM.[76]

Table 4: Applicants' Generation Outside of PJM

NERC	RTO	Exelon (MW)	PSEG (MW)
NPCC	ISO-NE	630	967
NPCC	NYISO	-	761
WECC	CAISO	-	443
SPP	SPP	795	-
ERCOT	ERCOT	3,651	2,026
SERC		1,755	-
MAIN	MISO	713	-
Total, Non-PJM		6,714	4,197

Note: Exelon's total is adjusted to account for double-counting of a unit connected to both ERCOT and SERC.

ISO-NE. Exelon's 630 MW of affiliated generation in ISO-NE includes New Boston and West Medway located within the Northeastern Massachusetts ("NEMA") load pocket and a few megawatts of generation located in Maine. PSEG's 967 MW of affiliated generation in ISO-NE includes Bridgeport Harbor and New Haven Harbor located in Southwest Connecticut and a few megawatts of generation located in New Hampshire. Thus, the smallest relevant market in which both Applicants' generation would compete is ISO-NE as a whole. Relative to ISO-NE's total generation (in excess of 30,000 MW), Exelon's affiliated generation is only 2 percent and PSEG's affiliated generation is only 3 percent of ISO-NE capacity. New England is generally an unconcentrated market, and

(i) Affirmatively demonstrates that the merging entities do not currently operate in the same geographic markets or that the extent of the business transactions in the same geographic market is *de minimis*; and

(ii) No intervenor has alleged that one of the merging entities is a perceived potential competitor in the same geographic market as the other.

[76] Although the discussion that follows presents market shares based on total capacity in the market (as opposed to Economic Capacity), market shares of Economic Capacity similarly would raise no competitive concerns in each of the relevant markets.

under any relevant condition studied in a Competitive Analysis Screen Applicants' shares would not cause HHI screen failures. The competitive nature of the ISO-NE market is exemplified by the fact that the Commission recently approved a transaction that involved the purchase of approximately 2,800 MW of capacity in New England by a generator that already owed about 2,000 MW of capacity in New England.[77] Since the relevant transaction here involves combining 630 MW of generation owned by Exelon with 957 MW of generation owned by PSEG, the results of a Competitive Screen Analysis of the instant merger is by definition less than that of the transaction that the Commission recently approved. No further analysis of the ISO-NE market is necessary.

ERCOT.[78] Exelon owns or controls via long-term contract 3,651 MW of generation in ERCOT,[79] mostly located in the North zone of ERCOT, with a small amount located in the Houston zone. PSEG owns 2,026 MW of affiliated generation in ERCOT, located in either the South or West zones. Since Applicants' generation is located in different zones within ERCOT, the only potentially relevant market is ERCOT as a whole. ERCOT's total generation is in excess of 80,000 MW. Exelon's affiliated generation is less than 5 percent and PSEG's affiliated generation is only 2.5 percent of ERCOT capacity. These shares are small and the combination of Applicants' shares presents no competitive concerns in ERCOT. Specifically, the "2ab" change in HHI is only about 20 points in peak periods and will be well under screen thresholds in other periods. A full Competitive Screen Analysis is not necessary to conclude that the effect of the merger in this market is not concerning.

Other Markets. In all other regions where Applicants own generation – WECC, Southwest Power Pool ("SPP"), SERC, NYISO and the portion of Mid-America

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[77] *USGen New England, Inc.*, 109 FERC ¶ 61,361 (2004). The Order describes applicant's (*i.e.*, Dominion's) analysis as follows: "For Economic Capacity, the post-acquisition New England market is unconcentrated (Herfindahl-Hirschman Index (HHI) < 1000)..."

[78] I have considered the effects of the merger on the ERCOT market despite the fact that it is not subject to the Commission's jurisdiction.

[79] This includes an 830 MW purchase (tolling agreement) from a plant that is capable of being dispatched into ERCOT or Entergy.

Interconnected Network, Inc. ("MAIN") that is not part of PJM – only one of the merging parties owns generation, so they "do not currently operate in the same geographic markets."

Capacity Markets in PJM

Q. PLEASE DESCRIBE PJM'S CURRENT MARKET FOR CAPACITY.

A. Beginning in June 2003, there was a single PJM capacity market that included the Mid-Atlantic region and the then-styled PJM Western region (*i.e.*, Allegheny Energy), with Daily and Monthly Unforced Capacity Credit markets. With the integration of ComEd, a Monthly (and multi-monthly) NICA (Northern Illinois Control Area) Installed Capacity Credit market was introduced. Effective January 1, 2005, there is a single capacity market that includes all current PJM members. UCAP remains the measure of relevance for the capacity market. Under UCAP, each unit's capacity is adjusted to account for its average forced outage rate.

Q. IS PJM CONSIDERING ALTERNATIVE MARKET STRUCTURES FOR THE CAPACITY MARKET?

A. Yes, the capacity market is expected to be significantly restructured, as part of an ongoing effort to improve system reliability and price signals. In addition to altering the price mechanism (for example, basing capacity payments on a "demand curve" that specifies the price of capacity given different levels of supply and ensuring prices that support entry at the point when capacity is needed), PJM is considering the introduction of a new series of auctions and a more formalized bilateral market for capacity. The proposal is to eventually have four-year forward base auctions.[80] Incremental Auctions would supplement Base Auctions three times during the four-year forward term. In addition, local capacity requirements may be imposed to ensure local reliability in

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[80] *PJM Reliability Pricing Model (RPM)*, DRAFT Business Rules, December 24, 2004. http://www.pjm.com/committees/working-groups/pjmramwg/downloads/reliability-pricing-model-business-rules.doc

transmission constrained areas. "Locational Delivery Areas" are "geographic areas within the PJM that have limited transmission capability to import capacity to satisfy the Unforced Capacity Obligation of the load within that area."[81] Locational constraints may be zonal-based (that is, for each EDC zone, such as PECO or PSEG), or may represent sub-zones (such as PS North) or combinations of zones (such as Eastern PJM). The zones to be created for the initial auction are under discussion, but it appears that locational zones will not be applicable until the 2007/2008 planning year. The current plan is that PJM East will become a zone in 2007-8 as will Southwestern MAAC (PEPCO and BG&E). The balance of Pre-2004 PJM (*i.e.*, with PJM East and Southwestern MAAC separated out) also will be a zone. Pending further analysis, each of the major new PJM members' former control areas (*e.g.* ComEd, AEP and DVP) will be separate zones. The zonal structure of markets will be reanalyzed in the future and appropriate changes made.

Q. GIVEN PJM'S ONGOING STUDY OF ALTERNATIVE CAPACITY MARKET MECHANISMS, HOW HAVE YOU ANALYZED PJM CAPACITY MARKETS?

A. I have analyzed two definitions of ICAP markets: Expanded PJM and PJM East. Expanded PJM is the currently relevant market. PJM East is one possible market definition that may exist in the future; indeed it is a planned market for 2007-8. While Southwestern MAAC would be a smaller market, it would not be a relevant market to this merger because Applicants do not own generation in this market.

Although the capacity credit markets are based on UCAP, lacking data on unit-specific forced outages, I analyzed the market based on installed capacity. The use of installed capacity should not materially impact the results of my analysis.[82]

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81 http://www.pjm.com/committees/working-groups/pjmramwg/downloads/20041216-draft-tariff-revisions-rpm-att-y.pdf

82 The use of ICAP is tantamount to assuming that the fleet of capacity owned by each market participant has the same forced outage rate. While not literally true, this will be nearly correct and any variation in forced outage rates could either increase or decrease market HHIs by small amounts.

Q. IS THE MARKET DEFINITION FOR ICAP ESSENTIALLY IDENTICAL TO THE MARKET DEFINITION FOR SUMMER SUPER-PEAK ENERGY?

A. Essentially, yes. For an Eastern zonal market, other PJM capacity can qualify up to the import limit. For all PJM markets, capacity can be imported provided *inter alia* that firm transmission into PJM is demonstrated. Therefore, in my analysis of ICAP, I have used the same 7,300 MW transmission limit for PJM East as I used for energy. For capacity that can reach Pre-2004 PJM, and thus be available for proration into PJM East, I have limited the imports to the 4,600 MW that were the maximum MW imported for ICAP purposes in 2003. For Expanded PJM, I have used the same 7,500 MW import limit that I used for the energy analysis. I assumed that imports were from external suppliers not affiliated with Applicants and purchased by four market participants with non-material shares of the market; unlike in the energy market analysis where imports would be fragmented among many suppliers, the capacity market requires a unit-specific commitment plus firm transmission and, hence, would tend to be significantly less fragmented.[83]

Q. WHAT DOES YOUR ANALYSIS SHOW FOR PJM EAST?

A. The capacity market for PJM East is highly concentrated, and the HHI change resulting from the merger is about 900 points, assuming none of Applicants' capacity is committed, as shown below in Table 12 and in Exhibit J-9. This calculation overstates the impact of the merger on capacity markets, given Exelon's 2006 load commitments and PSEG's 2006 capacity commitments. Indeed, taking these commitments into consideration, the impact on PJM East markets would be minimal. Moreover, as shown below, the mitigation required to cure the screen failure approximates the mitigation requirement for the PJM East Economic Capacity results, as expected.

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[83] In calculating the mitigation requirement to meet the thresholds of the Competitive Analysis Screen for capacity, I assumed divestiture to two parties with less than 5 percent capacity in either PJM East or Expanded PJM, consistent with my mitigation assumptions for energy as described earlier.

Table 12: ICAP Results, PJM East

	ICAP: PJM East		
	MW	Market Share	HHI
Exelon	7,180	18.0%	324
PSEG	10,134	25.4%	645
AEP	-	0.0%	-
Allegheny Energy	-	0.0%	-
Conectiv	4,800	12.0%	145
Constellation Energy	152	0.4%	0
DPL, Inc.	-	0.0%	-
Dominion	-	0.0%	-
Duke Energy	-	0.0%	-
Edison Mission Energy	-	0.0%	-
FirstEnergy	1,117	2.8%	8
Mirant	-	0.0%	-
NRG Energy	1,060	2.7%	7
PPL	2,071	5.2%	27
Reliant Energy	2,226	5.6%	31
Imports	7,300	18.3%	84
Others	3,862	9.7%	12
Total	39,902	100.0%	1,282
Post-Transaction HHI			2,196
HHI Change			914

As shown in Exhibit J-9, divestiture of 5,300 MW will eliminate screen failures in the ICAP market. Applicants are committing to divest 2,900 MW of generation, which means the remaining ICAP to be divested is no more than 2,400 MW.

Q. WHAT DOES YOUR ANALYSIS SHOW FOR EXPANDED PJM?

A. The capacity market for Expanded PJM is unconcentrated pre-merger, and barely moderately concentrated post-merger with an HHI change of 245 points, assuming none of Applicants' capacity is committed, as shown below in Table 13 and in Exhibit J-9. As with the PJM East capacity market analysis, this analysis overstates the impact of the merger on capacity markets, given Applicants' ICAP commitments. As shown below, the mitigation required to cure the screen failure is well less than the mitigation to which Applicants have committed.

Table 13: ICAP Results, Expanded PJM

	ICAP: Expanded PJM		
	MW	Market Share	HHI
Exelon	26,465	15.2%	230
PSEG	14,137	8.1%	66
AEP	23,980	13.7%	189
Allegheny Energy	9,724	5.6%	31
Conectiv	5,717	3.3%	11
Constellation Energy	7,279	4.2%	17
DPL, Inc.	4,799	2.7%	8
Dominion	21,700	12.4%	154
Duke Energy	2,736	1.6%	2
Edison Mission Energy	8,298	4.8%	23
FirstEnergy	3,732	2.1%	5
Mirant	6,051	3.5%	12
NRG Energy	2,834	1.6%	3
PPL	8,911	5.1%	26
Reliant Energy	6,805	3.9%	15
Imports	7,500	4.3%	5
Others	13,984	8.0%	4
Total	174,650	100.0%	799
Post-Transaction HHI			**1,044**
HHI Change			**245**

Ancillary Services

Q. WHAT ANCILLARY SERVICES ARE RELEVANT TO YOUR INQUIRY OF THE EFFECT ON COMPETITION?

A. Under the Merger Policy Statement, the Commission requires that Applicants consider the impact of a transaction on markets for ancillary services, specifically spinning reserves, non-spinning reserves and imbalance energy. PJM does not have an imbalance energy market distinct from its spot energy markets since there is no requirement to submit balanced schedules. Its spinning reserve market includes quick-start units, essentially peaking units. There is no separate non-spin reserve market (other than ICAP). PJM also operates a market-based regulation market. In reaching my conclusions about the impact of the merger on ancillary services markets, I rely in part on analyses conducted by PJM and its market monitor.

Q. PLEASE DESCRIBE THE SPINNING RESERVE MARKET.

A. There are two types of spinning reserve units: Tier 1 capacity, based on units already on line that are capable of increasing output within 10 minutes, and Tier 2 capacity that is synchronized to the grid and capable of providing spin, and turbines that are in condensing mode and capable of "quick start". At present, there are several spinning reserve zones: Mid-Atlantic (75 percent of largest contingency as synchronized 10-minute reserves plus 2 times the remaining 25 percent available as non-synchronized 10-minute reserves); Western (1.5 percent of peak load forecast); Northern Illinois (50 percent of ComEd's load ratio share of the largest system contingency); and Southern (Dominion load ratio share of the largest system contingency within VACAR, minus the available 15-minute quick start capability). Spinning reserves in the Mid-Atlantic zone are market-based while the West zone is cost-based.

In 2003, concentration was high in the Tier 2 spinning reserve market in the Mid-Atlantic region.[84,85] For this reason, all bid prices for Tier 2 spin are offer-capped on a basis related to costs.

In the PJM Mid-Atlantic in 2001 (no similar more recent data are available), there was a maximum capability of 3,033 MW of spinning reserves relative to maximum requirements of 2,271 MW.[86] Actual requirements ranged as high as 2,513 MW between 1999 and 2003. Lacking any other data, I have used these data in my analysis.

Q. WHAT IMPACT DOES THE MERGER HAVE ON THE SPIN MARKET?

A. Based on the somewhat limited data available, it appears that Exelon's spinning-capable units represent 6 percent of the Mid-Atlantic regulation capability, and PSEG's 39

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[84] All units operating on the PJM system are considered Tier 1 resources, except for those explicitly assigned to Tier 2 spinning.

[85] *2003 State of the Market*, PJM Market Monitoring Unit, March 4, 2004, page 28. My understanding is that the Market Monitor limited the Tier 2 units considered to condensing turbines.

[86] *Report on Spinning Reserve Market*, Joseph E. Bowring - Manager PJM Market Monitoring Unit.

percent. From the standpoint of a Competitive Analysis Screen, the combination of the two companies results in an HHI change of about 500 points, as shown below in Table 14 and in Exhibit J-10. However, Applicants' divestiture of fossil generation will divest spinning capability as well. None of the nuclear units is capable of providing spin.

Table 14: Spinning Reserves Market, Mid-Atlantic

	(MW)	Share
Market Capability	3,033	
Exelon	196	6%
PSEG	1,191	39%
Other	1,646	54%
Market Concentration		Moderate
HHI Change		507
Implied Divestiture		147
HHI Change		99

Q. PLEASE DESCRIBE THE REGULATION MARKET.

A. Regulation requirements apply to the Mid-Atlantic zone (1.1 percent of day-ahead peak load forecast for on-peak and valley load forecast for off-peak) and the Western zone (1 percent of daily forecast peak). At present, regulation in the Mid-Atlantic zone is market-based while the West zone is cost-based. In other words, the Commission has found that the market for regulation in the Mid-Atlantic is competitive. In the context of this merger, the Mid-Atlantic zone is the relevant regulation market.

The PJM regulation market in 2003 was moderately concentrated, but available regulation supply relative to demand for the service was large. According to the Market Monitor, in the PJM Mid-Atlantic region in 2003 there were 113 units qualified to produce about 2,011 MW of regulation capability, but requirements ranged from approximately 750 MW for the peak period to approximately 220 MW for the off-peak period.[87]

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87 *2003 State of the Market*, PJM Market Monitoring Unit, March 4, 2004, pages 27 and 136.

Q. WHAT IMPACT DOES THE MERGER HAVE ON THE REGULATION MARKET?

A. As shown in Table 15 and Exhibit J-11, Applicants have about 500 MW of regulation capability, about one-quarter of the capability identified by the Market Monitor.[88] More than half of their regulation capability is pumped storage. The balance is primarily baseload coal and mid-merit fossil.

The major component of regulation cost taken into account by PJM in scheduling regulation is the opportunity cost of the unit. Thus, during overnight, low price period, baseload coal units such as Keystone and Conemaugh are a source of regulation. Mid-merit units generally cannot provide regulation in low load periods since they generally are not on line.[89] Pumped storage units characteristically do not provide regulation during such periods because they are filling reservoirs. Moreover, as a result of efficiency losses of around 30 percent, they would be an uneconomic source of regulation. During high priced periods, the opportunity costs of baseload units are too high to be an economic source of regulation. Pumped storage units also generally are an uneconomic source of regulation. Their limited capability is used for peak shaving; hence their opportunity cost for providing regulation is high since it is based on their value during the highest-priced hours of the day.

It would be possible in principle to analyze the effects of the merger on regulation by time period. However, I have no data on unit- or owner-specific non-Applicant units so the analysis cannot be performed. What I have been able to ascertain is that the regulation requirement, which varies between about 200 and 700 MW, can be supplied at

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[88] I do not know whether all of the regulation capability that I have identified as belonging to Applicants was included in the 2,011 MW cited by the market monitor. The market monitor's figure was based on MW offered as regulation. My understanding from Applicants is that a significant share of the regulation-capable capacity that I have attributed to Applicants is rarely if ever sold as regulation.

[89] While inflexible steam units could theoretically provide regulation in these periods, they cannot do so if they are at minimum load, as is typical.

least twice over by the capacity controlled by non-Applicants. Hence, Applicants are not close to being pivotal in providing regulation.

Table 15: Regulation Market, PJM Mid-Atlantic

	(MW)	Share
Market Capability	2,011	
Exelon	267	13%
PSEG	241	12%
Other	1,504	75%

It also should be noted that the separate analysis of ancillary services, including both spin and regulation, is subject to the caveat that they cannot cleanly be analyzed separately from energy and each other. PJM co-optimizes energy and ancillary services. A given MW of capacity cannot be used to provide more than one service at any point in time. Moreover, because the energy price is a major element in pricing both regulation and spinning reserves, prices for the two products are intrinsically linked. Indeed, it is prices in the energy market that primarily determine the cost of procuring regulation and Tier 1 spin.

Mitigation

Q. HOW DID YOU DETERMINE THE MITIGATION REQUIRED TO CURE THE COMPETITIVE ANALYSIS SCREEN FAILURES?

A. The amount of mitigation required to eliminate screen failures in the Competitive Analysis Screen is largely a mathematical exercise: determining the post-merger market share for Applicants that yields HHI changes within the screen threshold, and then translating the reduction in Applicants' market share into the required megawatts of divesture. This is done for each of the time periods/price levels analyzed. Since Economic Capacity is an analysis of energy, the megawatts to be divested need to be adjusted for assumed outages to determine the equivalent capacity to be divested. This requires a determination of typical, or average, outages by season and by type of generation within the relevant categories of coal, mid-merit and peaking capacity. Based on this analysis, I determined the amount of divestiture required for each of the categories of units to be divested. A specific divestiture outcome that solves screen failures in all time periods will, in fact, reduce the HHI change to below target levels in other time periods.[90] For example, a divestiture that eliminates a screen failure in the Summer SP2 period, with a price of \$80/MWh, will over-mitigate the Winter SP period, which also has a price of \$80/MWh.

Thus, I undertook a two-step process to evaluate mitigation. First, I identified the "mitigation-eligible" units, which are essentially Applicants' generating units in PJM East that pass the delivered price test for each of the tranches analyzed. Of course, any unit eligible to mitigate screen failures at a lower price level is also eligible to mitigate screen failures at higher price levels, but not vice versa. Exhibit J-12 summarizes the mitigation-eligible units for each of the tranches for the Summer, Winter and Shoulder. I also determined the relevant characteristics for each of the relevant categories of capacity (nuclear baseload, and coal, mid-merit and peaking) in terms of outage factors by season and approximate price by season, as shown in Exhibit J-13.

The second step was to determine the target divestiture amounts that eliminate the HHI screen failures. These target amounts are also reflected in Exhibit J-13. As shown, I identified two scenarios: the amount of generation in PJM East to be mitigated (Scenario 1), and the amount of additional generation either inside or outside of PJM East required to mitigate any remaining screen failures in PJM Pre-2004 and Expanded PJM (Scenario 2). The particular set of units that cures the screen failures for the PJM East market falls a bit short of eliminating <u>all</u> of the screen failures in the other relevant PJM markets, merely because the mix of market supply in each of the time periods differs among the relevant markets. My previously introduced Table 1 reflects the results of these two scenarios. Detailed results are provided below and in Exhibit J-14.

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[90] In PJM East, where post-mitigation the market is moderately concentrated, I targeted a 99 point HHI change. (If the market had been highly concentrated, I would have mitigated to yield an HHI change of 49 points.) For PJM Pre-2004 and Expanded PJM, some time periods can be mitigated to a market HHI of 1,000 (unconcentrated) rather than to an HHI change of 99 points. Either represent passing the HHI screen.

Table 1: Mitigation Commitments (MW)

Generation Type	PJM East	PJM Mid-Atlantic*	Total
Nuclear	2,400	200	2,600
Mid-Merit**	1,900	0	1,900
Peaking	1,000	0	1,000
Total	5,300	200	5,500

* The additional 200 MW of commitment can be delivered anywhere in PJM Mid-Atlantic, including PJM East.

** At least 550 MW of the mid-merit divestiture will include coal-fired capacity. . Also, within the mid-merit category, 1,200 MW must be economic at a $55/MWh market price.

Mitigation of 5,300 MW of equivalent capacity in PJM East eliminates all screen failures in PJM East. This includes 2,400 MW of nuclear baseload capacity. Since the virtual divestiture of nuclear capacity will be in the form of energy, rather than capacity, the equivalent of 2,400 MW of nuclear baseload capacity is approximately 2,250 MW of firm 24X7 energy. This is based on Exelon's three-year average capacity factor on its nuclear fleet. The additional 200 MW of nuclear baseload capacity can be delivered anywhere in PJM Mid-Atlantic, including PJM East. In total, an equivalent of 2,600 MW of nuclear baseload capacity, or 2,450 MW of energy will be subject to divestiture.

With respect to the 1,900 of mid-merit capacity to be divested in PJM East, at least 550 MW will consist of coal-fired generation.

Table 2 presented previously reflects the Economic Capacity results for PJM East following the divestiture of 5,300 MW in PJM East. This is also included in Exhibit J-14. As shown, the HHI changes are all below 100 points, and the market is moderately concentrated post-mitigation.

Table 2: Economic Capacity, PJM East, Post-Mitigation

		Pre-Merger						Post-Merger				Mitigation and Post-Mitigation Results					
		Exelon		PSEG				EEG									
Period	Price	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	MW	Mkt Share	HHI	HHI Chg	Mitigation MW	Nuclear	Mkt Share	HHI	HHI Chg	MW Summer
S_SP1	$250	6,961	18.3%	9,658	25.4%	38,040	1,298	16,620	43.7%	2,227	929	4,877	2,201	30.9%	1,329	31	5,300
S_SP2	$80	6,032	18.4%	7,757	23.7%	32,786	1,218	13,788	42.1%	2,088	870	3,947	2,201	30.0%	1,273	55	4,300
S_P	$55	5,122	21.3%	5,957	24.8%	24,011	1,327	11,079	46.1%	2,385	1,058	3,947	2,201	29.7%	1,236	(91)	4,300
S_OP	$25	4,887	30.7%	2,631	16.5%	15,919	1,477	7,518	47.2%	2,492	1,015	2,201	2,201	33.4%	1,473	(4)	2,400
W_SP	$80	6,417	19.3%	7,796	23.4%	33,333	1,228	14,213	42.6%	2,128	900	4,061	2,289	30.5%	1,291	63	4,300
W_P	$55	5,451	22.5%	5,770	23.8%	24,281	1,323	11,221	46.2%	2,390	1,067	4,061	2,289	29.5%	1,222	(101)	4,300
W_OP	$30	5,167	26.6%	3,594	18.5%	19,398	1,324	8,761	45.2%	2,311	987	2,833	2,289	30.6%	1,297	(27)	2,950
SH_SP	$65	4,896	20.4%	5,095	21.3%	23,958	1,187	9,991	41.7%	2,057	870	3,233	1,800	28.2%	1,181	(6)	4,300
SH_P	$45	4,675	26.0%	2,935	16.3%	17,988	1,257	7,610	42.3%	2,105	848	2,196	1,800	30.1%	1,287	30	2,950
SH_OP	$20	4,338	30.3%	2,051	14.3%	14,305	1,406	6,389	44.7%	2,276	870	1,800	1,800	32.1%	1,389	(17)	2,400

Table 16 below and Exhibit J-14 present the Economic Capacity results for PJM Pre-2004 following the divestiture of 5,500 MW in total. As shown the HHI changes are all at or below 100 points, and the market is unconcentrated to moderately concentrated post-mitigation. I note that there is one time period when the HHI is 1,002 points, with an HHI change of 106 points. Ultimately, the precise HHI change depends on which specific plants are sold and who the specific buyers are. As a result, I would consider these as passing the HHI screen.

Table 16: Economic Capacity, PJM Pre-2004, Post-Mitigation

		Pre-Merger						Post-Merger				Mitigation and Post-Mitigation Results					
		Exelon		PSEG				EEG									
Period	Price	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	MW	Mkt Share	HHI	HHI Chg	Mitigation MW	Nuclear	Mkt Share	HHI	HHI Chg	MW Summer
S_SP1	$250	10,508	13.6%	11,210	14.5%	77,273	896	21,718	28.1%	1,291	395	5,061	2,385	21.6%	1,002	106	5,500
S_SP2	$80	9,545	13.8%	9,288	13.4%	69,380	885	18,834	27.2%	1,254	369	4,130	2,385	21.2%	995	110	4,500
S_P	$55	7,976	14.6%	7,455	13.7%	54,517	971	15,431	28.3%	1,371	400	4,130	2,385	20.7%	1,043	72	4,500
S_OP	$25	6,416	25.9%	3,189	12.9%	24,749	1,217	9,605	38.8%	1,885	668	2,385	2,385	29.2%	1,277	60	2,600
W_SP	$80	9,899	14.1%	9,334	13.3%	70,238	883	19,233	27.4%	1,257	374	4,252	2,480	21.3%	993	110	4,500
W_P	$55	8,299	15.1%	7,273	13.2%	54,932	968	15,571	28.4%	1,368	400	4,252	2,480	20.6%	1,034	66	4,500
W_OP	$30	7,701	17.7%	4,946	11.4%	43,557	985	12,648	29.0%	1,386	401	3,024	2,480	22.1%	1,063	78	3,150
SH_SP	$65	7,866	15.6%	6,263	12.4%	50,501	951	14,129	28.0%	1,337	386	3,383	1,950	21.3%	1,043	92	4,500
SH_P	$45	6,936	17.2%	4,070	10.1%	40,251	1,004	11,006	27.3%	1,353	349	2,346	1,950	21.5%	1,090	86	3,150
SH_OP	$20	5,472	26.4%	2,440	11.8%	20,715	1,206	7,912	38.2%	1,828	622	1,950	1,950	28.8%	1,242	36	2,600

Finally Table 17 below and Exhibit J-14 present the Economic Capacity results for Expanded PJM following the divestiture of 5,500 MW. This is also included in Exhibit J-14. As shown, with one exception the HHI changes are all below 100 points or the market is unconcentrated. The one exception is an HHI change of 102 points with an HHI of 1,004. Again, while a technical violation of the screen, I view this as reflecting a fully mitigated result.

Table 17: Expanded PJM, Post Mitigation

		Pre-Merger						Post-Merger				Mitigation and Post-Mitigation Results					
		Exelon		PSEG				EEG									
Period	Price	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	MW	Mkt Share	HHI	HHI Chg	Mitigation MW	Nuclear	Mkt Share	HHI	HHI Chg	MW Summer Equivalent
S_SP1	$250	24,354	14.9%	12,929	7.9%	163,707	774	37,283	22.8%	1,009	235	5,061	2,385	19.7%	892	118	5,500
S_SP2	$80	23,384	15.2%	11,006	7.1%	154,162	795	34,390	22.3%	1,011	216	4,130	2,385	19.6%	910	115	4,500
S_P	$55	18,813	15.3%	9,153	7.5%	122,719	902	27,966	22.8%	1,130	228	4,130	2,385	19.4%	1,004	102	4,500
S_OP	$25	16,950	22.3%	3,189	4.2%	76,038	1,447	20,139	26.5%	1,634	187	2,385	2,385	23.3%	1,483	36	2,600
W_SP	$80	24,013	15.4%	11,053	7.1%	156,250	804	35,067	22.4%	1,021	217	4,252	2,480	19.7%	917	113	4,500
W_P	$55	19,150	15.3%	8,973	7.2%	124,828	909	28,123	22.5%	1,130	221	4,252	2,480	19.1%	1,003	94	4,500
W_OP	$30	18,373	17.8%	4,946	4.8%	102,979	1,102	23,319	22.6%	1,274	172	3,024	2,480	19.7%	1,158	56	3,150
SH_SP	$65	19,460	16.4%	7,672	6.5%	118,586	850	27,133	22.9%	1,063	213	3,383	1,950	20.0%	951	101	4,500
SH_P	$45	15,842	16.5%	5,462	5.7%	95,869	932	21,304	22.2%	1,120	188	2,346	1,950	19.8%	1,023	91	3,150
SH_OP	$20	12,975	21.8%	2,440	4.1%	59,411	1,428	15,415	26.0%	1,608	180	1,950	1,950	22.7%	1,453	25	2,600

Vertical Market Power

Q. ARE THERE ANY OTHER ISSUES THAT WOULD AFFECT COMPETITION IN THE RELEVANT MARKETS?

A. The other primary potential market power issue is vertical market power -- control over electric transmission, generating sites or fuels supplies. There are no issues about electric transmission market power since all of Applicants' transmission is controlled by PJM.

Q. WHAT IS THE ISSUE CONCERNING AN APPLICANT'S CONTROL OVER ESSENTIAL FUELS OR DELIVERY SYSTEMS?

A. In the context of long-term capacity markets, the issue is whether the merging parties can foreclose or impede the entry of competing generators. There also is a shorter-term issue of whether the merger might increase the incentive or ability to raise rivals costs.

Q. WHAT CONTROL DO APPLICANTS HAVE OVER FUELS OR FUEL DELIVERY SYSTEMS?

A. As described earlier, PECO's LDC operations serve a limited area in eastern Pennsylvania. PECO offers transportation services to all of its customers, and a large number of customers obtain their gas commodity from third-party suppliers. PECO's LDC system is easily bypassed by large customers. While PECO Energy is permitted to discount its transportation rate to meet competitive pressures, there are a number of customers on PECO's system who have opted to bypass the utility completely and connect directly to an interstate gas pipeline (*e.g.*, Sun Oil and Tosco have done so). Existing larger customers have used the threat of bypass to achieve reduced rates. As noted earlier, PECO provides gas distribution service to only three unaffiliated electric generators totaling less than 200 MW. These are either industrial facilities that consume the bulk of their electricity on-site or facilities that use natural gas as a secondary fuel. Other independent generators located in their service area take service directly from the pipeline. Newly built facilities could readily avoid PECO's small service area or connect directly to an interstate pipeline.

PSE&G's gas distribution system in New Jersey serves eight current or former QFs under contract to the utility, as well as two merchant generators: the Tosco plant (172 MW) and the Williams Red Oak plant (765 MW). These generating facilities served by PSE&G are under long-term contracts or discounted tariffs. PSE&G also provides transportation service to affiliated generators in its service area.

With respect to both PECO and PSE&G, it is not necessary that new generation would seek to be connected to an LDC as opposed to direct interconnection with a pipeline system.

Q. WHAT FIRM TRANSMISSION RIGHTS DO APPLICANTS HAVE ON INTERSTATE GAS PIPELINES SERVING PJM?

A. The three largest interstate pipelines serving Pennsylvania and New Jersey are Tennessee Gas Pipeline, Texas Eastern Transmission and Transcontinental Gas Pipe Line. These pipelines represent about 90 percent of capacity entering New Jersey and about 70 percent of capacity entering Pennsylvania. Columbia Gas Transmission and Dominion Transmission are the other two significant pipelines serving Pennsylvania (12 percent and 10 percent of entering capacity, respectively).[91] I examined Applicants' firm transmission reservations on each of these pipelines (excluding those expiring prior to 2006 with no rollover rights). Exelon's total firm transmission reservations total about 500 mmcf/day,

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[91] Only some of this capacity into New Jersey and Pennsylvania is relevant for PJM East.

and PSE&G's total about 1bcf/day (reflecting the fact that PSE&G is a much larger LDC than PECO). ER&T also has firm transmission commitments for delivery into the market area. PECO's firm transportation rights are fully committed to meet retail customer load. The upstream market, no doubt, is not highly concentrated, as pipeline ownership (measured by firm transportation rights) is diverse. Moreover, Applicants cannot withhold these rights to reduce supply since failure to use rights simply increases the amount of release capacity available to competitors.

The mere ownership of LDC operations does not give rise to a concern that Applicants will use self-dealing or other means of using the gas LDC to favor affiliated activities. Distribution tariffs are regulated by the respective state public utility commissions, which impose open access distribution requirements. The ability to earn even the ceiling rates in distribution tariffs frequently is constrained by bypass alternatives or the existence of long-term (sometimes discounted) contracts. The ability of an LDC to impede entry is very unlikely since new generation can be sited so as to connect directly to a transmission pipeline system. Other vertical concerns are not present. Both Pennsylvania and New Jersey have in place codes of conduct between gas and electric affiliates, and both utilities are governed by FERC Order No. 2004. In any event, the amount of generation served is so small that knowledge of customers' operations is of no commercial value to electric generation. In short, none of the vertical concerns that the Commission focused upon in prior vertical mergers exist in this merger and the transaction does not create or enhance vertical market power.

Q. DID YOU CONDUCT ANY FURTHER ANALYSIS TO DEMONSTRATE THAT VERTICAL CONCERNS ARE NOT PRESENT?

A. I completed the downstream portion of the required analysis under Section 33.4 of the Commission's regulations. That framework requires that the structure of downstream markets be analyzed using the same delivered price test methodology as in the horizontal market power analysis, but with gas-fired generation deemed to be controlled by (*i.e.*, is assigned to) its gas supplier rather than its owner. I attributed gas-fired generation to the upstream suppliers, *i.e.*, the pipeline that serves it. For power plants directly connected to a single pipeline, the entire capacity of the plant is attributed to the pipeline. If the pipeline is jointly owned, the capacity is divided among the pipeline owners. For power plants directly connected to multiple pipelines, the plant's capacity is divided into equal shares and attributed to the pipelines that are connected. If a pipeline connection cannot be determined, or the plant is served by an LDC (other than Applicants' LDC) that is fed by multiple pipelines, the capacity is assigned to the actual owner of the unit. For plants served by PECO or PSE&G, as well as for gas-fired plants owned by Applicants, I assigned the capacity to Applicants. These are detailed in Table 18 below.

Table 18: Unaffiliated Gas-Fired Generation Served by Applicants

LDC	Owner	Location	Unit Name	Capacity (MW)
PSE&G	Newmarket Power	PJM - East	Bayonne	165
PSE&G	Newmarket Power	PJM - East	Camden	149
PSE&G	Sunoco	PJM - East	Eagle Point	195
PSE&G	Trenton District Energy Co.	PJM - East	TDEC	12
PSE&G	Calpine/FirstEnergy	PJM - East	Parlin	125
PSE&G	Newmarket Power	PJM - East	Newark Bay	123
PSE&G	FPL/Tractabel	PJM - East	Sayreville	290
PSE&G	AEP	PJM - East	Red Oak	765
PSE&G	Goldman Sachs	PJM - East	Tosco	172
PSE&G	Calpine	PJM - East	Newark Boxboard	52
PECO	Merck	PJM - East	Merck	65
PECO	Kimberly Clark	PJM - East	Kimberly Clark	50
PECO	American Refuel	PJM - East	American Refuel	83

I analyzed the downstream market for PJM East, PJM Pre-2004 and Expanded PJM. After taking into account Applicants' mitigation commitments, neither the PJM Pre-2004 nor the Expanded PJM markets are highly concentrated post-merger, as shown in Exhibit J-15. However, the PJM East market remains highly concentrated post-mitigation. In performing this analysis, I only counted the divestiture of nuclear or coal units; if some of the divested units are oil-fired, they too would represent a reduction in Applicants' market share and would likely reduce concentration below 1800. Nevertheless, since the PJM East downstream market is highly concentrated, consistent with the Commission's regulations, I conducted an analysis of the PJM East upstream market. The analysis of the upstream market requires that the structure of control of transportation capacity be examined. For this purpose, I allocated control of gas transportation pipelines to holders of firm capacity rights, with any unsubscribed capacity allocated to the pipeline owner. Details of this approach are provided below and in Exhibit No. J-4.

As shown in Exhibit J-17, I found that the PJM East upstream market is not highly concentrated and thus the competitive conditions in the market are not conducive to a vertical foreclosure strategy.

The weight of the evidence indicates that the likelihood of a successful strategy of vertical foreclosure or raising rivals' cost is simply not present. Downstream markets in PJM Pre-2004 and Expanded PJM are not highly concentrated, and even in PJM East the downstream market is mostly just above the threshold levels for a concentrated market. Moreover, the ability of an LDC such as PECO or PSE&G to successfully implement a foreclosure strategy is unlikely. This is further evidenced by the result that the upstream market in PJM East is not highly concentrated.

Q. ARE THERE ANY OTHER VERTICAL ISSUES OF CONCERN IN THIS MERGER?

A. No. This merger should raise no other vertical market power concerns. The Commission also has considered competition in transmission services and has examined whether the combination of ownership of transmission facilities creates the opportunity or incentive for the merging parties to restrict access to transmission. Here, all of Applicants' transmission assets are under the control of PJM.

Q. DO APPLICANTS EXERCISE CONTROL OVER THE AVAILABLE GENERATION SITES?

A. No. I was unable to identify any special barriers to entry in this regard. The service areas of these Applicants are relatively small, and the relevant geographic markets in PJM encompass a large region and includes many possible generating sites. Entrants who could compete in areas potentially affected by this merger would not need to locate new facilities in Applicants' service areas or connect to Applicants' transmission systems. In any event, PJM, not Applicants, controls the interconnection process for new generation. Thus Applicants' RTO membership should moot any concerns in this regard.

Q. EARLIER, YOU STATED THAT THE COMMISSION HAS FOUND LONG-TERM MARKETS TO BE PRESUMPTIVELY COMPETITIVE. PLEASE ELABORATE.

A. In Order No. 888, the Commission in referring to a decision in *Entergy Services, Inc.*, noted that "after examining generation dominance in many different cases over the years, we have yet to find an instance of generation dominance in long-run bulk power markets."[92] In the Merger NOPR, the Commission stated that "[a]s restructuring in the wholesale and retail electricity markets progresses, short-term markets appear to be growing in importance. The role of long-term capacity markets appears to be diminishing."[93] While the Commission has indicated its intent to review the presumption that long-term markets are competitive, there is no evidence to overcome that presumption. Certainly, the entry of new generation into PJM and its ownership by numerous independent entities shows that entry is not constrained.

Q. IS THERE ANY EVIDENCE THAT THERE WILL BE ENTRY INTO PJM WITHIN THE NEXT FEW YEARS?

A. Yes. Although PJM has been capacity-long in the past few years, its reserve margin is expected to decline relatively quickly given planned retirements and load growth. PJM forecasts retirements of approximately 3,000 MW and additions of approximately 5,000 MW by 2006/2007. Moreover, as part of the Reliability Pricing Model being considered by PJM, the introduction of a demand curve-based capacity payment is intended to encourage necessary generation investment when needed.

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92 Order No. 888 at 31,649 n.86 (citation omitted).

93 Merger NOPR, *op. cit.*, at 20.

VI. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION.

A. I recommend that the Commission determine that this merger will not have an adverse effect on competition in markets subject to its jurisdiction.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

EXHIBITS

Tables

Charles
River
Associates

Exhibit J-2

WILLIAM H. HIERONYMUS — Vice President

Ph.D.	Economics, University of Michigan
M.A.	Economics, University of Michigan
B.A.	Social Science, University of Iowa

William Hieronymus has consulted extensively to managements of electricity and gas companies, their counsel, regulators, and policymakers. His principal areas of concentration are the structure and regulation of network utilities and associated management, policy, and regulatory issues. Dr. Hieronymus has spent the last fourteen years working on the restructuring and privatization of utility systems in the U.S. and internationally. In this context he has assisted the managements of energy companies on corporate and regulatory strategy, particularly relating to asset acquisition and divestiture. He has testified extensively on regulatory policy issues and on market power issues related to mergers and acquisitions. In his twenty-five years of consulting to this sector, he also has performed a number of more specific functional tasks, including analyzing potential investments; assisting in negotiation of power contracts, tariff formation, demand forecasting, and fuels market forecasting. Dr. Hieronymus has testified frequently on behalf of energy sector clients before regulatory bodies, federal courts, and legislative bodies in the United States and United Kingdom. He has contributed to numerous projects, including the following:

ELECTRICITY SECTOR STRUCTURE, REGULATION, AND RELATED MANAGEMENT AND PLANNING ISSUES

U.S. Market Restructuring Assignments

- Dr. Hieronymus serves as an advisor to the senior executives of electric utilities on restructuring and related regulatory issues, and he has worked with senior management in developing strategies for shaping and adapting to the emerging competitive market in electricity. Related to some of these assignments, he has testified before state agencies on regulatory policies and on contract and asset valuation.
- For utilities seeking merger approval, Dr. Hieronymus has prepared and testified to market power analyses at FERC and before state commissions. He also has assisted in discussions with the Antitrust Division of the Department of Justice and in responding to information requests. The mergers on which Dr. Hieronymus has testified include both electricity mergers and combination mergers involving electricity and gas companies. Among the major mergers on which he has testified are Sempra (Enova and Pacific Enterprises), Xcel (New Century Energy and Northern States Power),

Exelon (Commonwealth Edison and Philadelphia Electric), AEP (American Electric Power and Central and Southwest), Dynegy-Illinois Power, Con Edison-Orange and Rockland, Dominion-Consolidated Natural Gas, NiSource-Columbia Energy, E-on-PowerGen/LG&E and NYSEG-RG&E. He also submitted testimony in mergers that were terminated for unrelated reasons, including Entergy-Florida Power and Light and Consolidated Edison-Northeast Utilities. Testimony on similar topics has been filed for a number of smaller utility mergers and for asset acquisitions. Dr Hieronymus has also assisted numerous clients in the pre-merger screening of potential acquisitions and merger partners.

- For utilities seeking to establish or extend market rate authority, Dr. Hieronymus has provided numerous analyses concerning market power in support of submissions under Sections 205 of the Federal Power Act.

- For utilities and power pools engaged in restructuring activities, he has assisted in examining various facets of proposed reforms. Such analysis has included features of the proposals affecting market efficiency and those that have potential consequences for market power. Where relevant, the analysis also has examined the effects of alternative reforms on the client's financial performance and achievement of other objectives.

- For generators and marketers, Dr. Hieronymus has testified extensively in the regulatory proceedings concerning the electricity crisis in the WECC that occurred during May 2000 and May 2001. His testimony concerned, *inter alia*, the economics of long term contracts entered into during that period the behavior of market participants during the crisis period and the nexus between purportedly dysfunctional spot markets and forward contracts.

- For the New England Power Pool (NEPOOL), Dr. Hieronymus examined the issue of market power in connection with NEPOOL's movement to market-based pricing for energy, capacity, and ancillary services. He also assisted the New England utilities in preparing their market power mitigation proposal. The main results of his analysis were incorporated in NEPOOL's market power filing before FERC and in ISO-New England's market power mitigation rules.

- For a coalition of independent generators, he provided affidavits advising FERC on changes to the rules under which the northeastern U.S. power pools operate.

- As part of a large planning and analysis team, Dr. Hieronymus assisted a Midwest utility in developing an innovative proposal for electricity industry restructuring.

- Dr. Hieronymus has contributed substantially to projects dealing with the restructuring of the California electricity industry. In this context he also is a witness in California and FERC proceedings on the subject of market power and mitigation and more recently before FERC in connection with transactions related to PG&E's bankruptcy and on the contracts signed between merchant generators and various buyers.

Valuation of Utility Assets in North America

- Dr. Hieronymus has testified in state securitization and stranded cost quantification proceedings, primarily in forecasting the level of market prices that should be used in assessing the future revenues and the operating contribution earned by the owner of utility assets in energy and capacity markets. The market price analyses are tailored to the specific features of the market in which a utility will operate and reflect transmission-constrained trading over a wide geographic area. He also has testified in rebuttal to other parties' testimony concerning stranded costs, and has assisted companies in internal stranded cost and asset valuation studies.

- He was the primary valuation witness on behalf of a western utility in an arbitration proceeding concerning the value of a combined cycle plant coming off lease that the utility wished to purchase.

- He assisted a bidder in determining the commercial terms of plant purchase offers as well as assisting clients in assessing the regulatory feasibility of potential acquisitions and mergers.

Other U.S. Utility Engagements

- Dr. Hieronymus has contributed to the development of several benchmarking analyses for U.S. utilities. These have been used in work with clients to develop regulatory proposals, set cost reduction targets, restructure internal operations, and assess merger savings.

- Dr. Hieronymus was a co-developer of a market simulation package tailored to region-specific applications. He and other senior personnel have conducted numerous multi-day training sessions using the package to help utility clients in educating management regarding the consequences of wholesale and retail deregulation and in developing the skills necessary to succeed in this environment.

- He has made numerous presentations to U.S. utility managements regarding overseas electricity systems.

- For an East Coast electricity holding company, Dr. Hieronymus prepared and testified to an analysis of the logic and implementation issues concerning utility-sponsored conservation and demand-management programs as alternatives to new plant construction.

- In connection with nuclear generating plants nearing completion, he has testified in Pennsylvania, Louisiana, Arizona, Illinois, Missouri, New York, Texas, Arkansas, New Mexico, and before the Federal Energy Regulatory Commission regarding plant-in-service rate cases on the issues of equitable and economically efficient treatment of plant costs for tariff-setting purposes, regulatory treatment of new plants in other jurisdictions, the prudence of past system planning decisions and assumptions, performance incentives, and the life-cycle costs and benefits of the units. In these and other utility regulatory proceedings, Dr. Hieronymus and his colleagues have provided extensive support to counsel, including preparation of interrogatories, cross-examination support, and assistance in writing briefs.

- On behalf of utilities in the states of Michigan, Massachusetts, New York, Maine, Indiana, Pennsylvania, New Hampshire, and Illinois, he has submitted testimony in regulatory proceedings on the economics of completing nuclear generating plants that were then under construction. His testimony has covered the likely cost of plant completion; forecasts of operating performance; and extensive analyses of the impacts of completion, deferral, and cancellation upon ratepayers and shareholders. For the senior managements and boards of utilities engaged in nuclear plant construction, Dr. Hieronymus has performed a number of highly confidential assignments to support strategic decisions concerning the continuance of construction.

- For an eastern Pennsylvania utility that suffered a nuclear plant shutdown due to NRC sanctions relating to plant management, he filed testimony regarding the extent to which replacement power cost exceeded the costs that would have occurred but for the shutdown.

- For a major Midwestern utility, Dr. Hieronymus headed a team that assisted senior management in devising its strategic plans, including examination of such issues as plant refurbishment/life extension strategies, impacts of increased competition, and available diversification opportunities.

- On behalf of two West Coast utilities, Dr. Hieronymus testified in a needs certification hearing for a major coal-fired generation complex concerning the economics of the facility relative to competing sources of power, particularly unconventional sources and demand reductions.

- For a large western combination utility, he participated in a major 18-month effort to provide the client with an integrated planning and rate case management system.

- For two Midwestern utilities, Dr. Hieronymus prepared an analysis of intervenor-proposed modifications to the utilities' resource plans. He then testified on their behalf before a legislative committee.

U.K. Assignments

- Following promulgation of the white paper that established the general framework for privatization of the electricity industry in the United Kingdom, Dr. Hieronymus participated extensively in the task forces charged with developing the new market system and regulatory regime. His work on behalf of the Electricity Council and the twelve regional distribution and retail supply companies focused on the proposed regulatory regime, including the price cap and regulatory formulas, and distribution and transmission use of system tariffs. He was an active participant in industry-government task forces charged with creating the legislation, regulatory framework, initial contracts, and rules of the pooling and settlements system. He also assisted the regional companies in the valuation of initial contract offers from the generators, including supporting their successful refusal to contract for the proposed nuclear power plants that subsequently were canceled as being non-commercial.

- During the preparation for privatization, Dr. Hieronymus assisted several individual U.K. electricity companies in understanding the evolving system, in developing use of system tariffs, and in enhancing commercial capabilities in power purchasing and contracting. He continued to advise a number of clients, including regional companies, power developers, large industrial customers, and financial institutions on the U.K. power system for a number of years after privatization.

- Dr. Hieronymus assisted four of the regional electricity companies in negotiating equity ownership positions and developing the power purchase contracts for a 1,825 megawatt combined cycle gas station. He also assisted clients in evaluating other potential generating investments including cogeneration and non-conventional resources.

- Dr. Hieronymus also has consulted on the separate reorganization and privatization of the Scottish electricity sector. Part of his role in that privatization included advising the larger of the two Scottish companies and, through it, the Secretary of State on all phases of the restructuring and privatization, including the drafting of regulations, asset valuation, and company strategy.

- He assisted one of the Regional Electricity Companies in England and Wales in the 1993 through 1995 regulatory proceedings that reset the price caps for its retailing and distribution businesses. Included in this assignment was consideration of such policy issues as incentives for the economic purchasing of power, the scope of price control, and the use of comparisons among companies as a basis for price regulation. Dr. Hieronymus's model for determining network refurbishment needs was used by the regulator in determining revenue allowances for capital investments.

- He assisted one of the Regional Electricity Companies in its defense against a hostile takeover, including preparation of its submission to the Cabinet Minister who had the responsibility for determining whether the merger should be referred to the competition authority.

Assignments Outside the U.S. and U.K.

- Dr. Hieronymus assisted a large state-owned European electricity company in evaluating the impacts of the 1997 EU directive on electricity that *inter alia* requires retail access and competitive markets for generation. The assignment included advice on the organizational solution to elements of the directive requiring a separate transmission system operator and the business need to create a competitive marketing function.

- For the European Bank for Reconstruction and Development, he performed analyses of least-cost power options and evaluated the return on a major investment that the Bank was considering for a partially completed nuclear plant in Slovakia. Part of this assignment involved developing a forecast of electricity prices, both in Eastern Europe and for potential exports to the West.

- For the OECD he performed a study of energy subsidies worldwide and the impact of subsidy elimination on the environment, particularly on greenhouse gases.
- For the Magyar Villamos Muvek Troszt, the electricity company of Hungary, Dr. Hieronymus developed a contract framework to link the operations of the different entities of an electricity sector in the process of moving from a centralized command-and-control system to a decentralized, corporatized system.
- For Iberdrola, the largest investor-owned Spanish electricity company, he assisted in development of their proposal for a fundamental reorganization of the electricity sector, its means of compensating generation and distribution companies, its regulation, and the phasing out of subsidies. He also has assisted the company in evaluating generation expansion options and in valuing offers for imported power.
- Dr. Hieronymus contributed extensively to a project for the Ukrainian Electricity Ministry, the goal of which was to reorganize the Ukrainian electricity sector and prepare it for transfer to the private sector and the attraction of foreign capital. The proposed reorganization is based on regional electric power companies, linked by a unified central market, with market-based prices for electricity.
- At the request of the Ministry of Power of the USSR, Dr. Hieronymus participated in the creation of a seminar on electricity restructuring and privatization. The seminar was given for 200 invited Ministerial staff and senior managers for the USSR power system. His specific role was to introduce the requirements and methods of privatization. Subsequent to the breakup of the Soviet Union, Dr. Hieronymus continued to advise both the Russian energy and power ministry and the government-owned generation and transmission company on restructuring and market development issues.
- On behalf of a large continental electricity company, Dr. Hieronymus analyzed the proposed directives from the European Commission on gas and electricity transit (open access regimes) and on the internal market for electricity. The purpose of this assignment was to forecast likely developments in the structure and regulation of the electricity sector in the common market and to assist the client in understanding their implications.
- For the electric utility company of the Republic of Ireland, he assessed the likely economic benefit of building an interconnector between Eire and Wales for the sharing of reserves and the interchange of power.
- For a task force representing the Treasury, electricity generating, and electricity distribution industries in New Zealand, Dr. Hieronymus undertook an analysis of industry structure and regulatory alternatives for achieving the economically efficient generation of electricity. The analysis explored how the industry likely would operate under alternative regimes and their implications for asset valuation, electricity pricing, competition, and regulatory requirements.

TARIFF DESIGN METHODOLOGIES AND POLICY ISSUES

- Dr. Hieronymus participated in a series of studies for the National Grid Company of the United Kingdom and for ScottishPower on appropriate pricing methodologies for transmission, including incentives for efficient investment and location decisions.
- For a U.S. utility client, he directed an analysis of time-differentiated costs based on accounting concepts. The study required selection of rating periods and allocation of costs to time periods and within time periods to rate classes.
- For EPRI, Dr. Hieronymus directed a study that examined the effects of time-of-day rates on the level and pattern of residential electricity consumption.
- For the EPRI-NARUC Rate Design Study, he developed a methodology for designing optimum cost-tracking block rate structures.
- On behalf of a group of cogenerators, Dr. Hieronymus filed testimony before the Energy Select Committee of the UK Parliament on the effects of prices on cogeneration development.
- For the Edison Electric Institute (EEI), he prepared a statement of the industry's position on proposed federal guidelines regarding fuel adjustment clauses. He also assisted EEI in responding to the U.S. Department of Energy (DOE) guidelines on cost-of-service standards.
- For private utility clients, Dr. Hieronymus assisted in the preparation both of their comments on draft FERC regulations and of their compliance plans for PURPA Section 133.
- For a state utilities commission, Dr. Hieronymus assessed its utilities' existing automatic adjustment clauses to determine their compliance with PURPA and recommended modifications.
- For DOE, he developed an analysis of automatic adjustment clauses currently employed by electric utilities. The focus of this analysis was on efficiency incentive effects.
- For the commissioners of a public utility commission, Dr. Hieronymus assisted in preparation of briefing papers, lines of questioning, and proposed findings of fact in a generic rate design proceeding.

SALES FORECASTING METHODOLOGIES FOR GAS AND ELECTRIC UTILITIES

- For the White House Sub-Cabinet Task Force on the future of the electric utility industry, Dr. Hieronymus co-directed a major analysis of "least-cost planning studies" and "low-growth energy futures." That analysis was the sole demand-side study commissioned by the task force, and it formed a basis for the task force's conclusions concerning the need for new facilities and the relative roles of new construction and customer side-of-the-meter programs in utility planning.

- For a large eastern utility, Dr. Hieronymus developed a load forecasting model designed to interface with the utility's revenue forecasting system-planning functions. The model forecasts detailed monthly sales and seasonal peaks for a 10-year period.
- For DOE, he directed development of an independent needs assessment model for use by state public utility commissions. This major study developed the capabilities required for independent forecasting by state commissions and provided a forecasting model for their interim use.
- For state regulatory commissions, Dr. Hieronymus has consulted in the development of service area-level forecasting models of electric utility companies.
- For EPRI, he authored a study of electricity demand and load forecasting models. The study surveyed state-of-the-art models of electricity demand and subjected the most promising models to empirical testing to determine their potential for use in long-term forecasting.
- For a Midwestern electric utility, he provided consulting assistance in improving the client's load forecast, and testified in defense of the revised forecasting models.
- For an East Coast gas utility, Dr. Hieronymus testified with respect to sales forecasts and provided consulting assistance in improving the models used to forecast residential and commercial sales.

OTHER STUDIES PERTAINING TO REGULATED AND ENERGY COMPANIES

- In a number of antitrust and regulatory matters, Dr. Hieronymus has performed analyses and litigation support tasks. These cases have included Sherman Act Section 1 and 2 allegations, contract negotiations, generic rate hearings, ITC hearings, and a major asset valuation suit. In a major antitrust case, he testified with respect to the demand for business telecommunications services and the impact of various practices on demand and on the market share of a new entrant. For a major electrical equipment vendor, Dr. Hieronymus testified on damages with respect to alleged defects and associated fraud and warranty claims. In connection with mergers for which he is the market power expert, Dr. Hieronymus assists clients in Hart-Scott-Rodino investigations by the Antitrust Division of the U.S. Department of Justice and the Federal Trade Commission. In an arbitration case, he testified as to changed circumstances affecting the equitable nature of a contract. In a municipalization case, he testified concerning the reasonable expectation period for the supplier of power and transmission services to a municipality. In two Surface Transportation Board proceedings, he testified on the sufficiency of product market competition to inhibit the exercise of market power by railroads transporting coal to power plants.

- For a landholder, Dr. Hieronymus examined the feasibility and value of an energy conversion project that sought a long-term lease. The analysis was used in preparing contract negotiation strategies.
- For an industrial client considering development and marketing of a total energy system for cogeneration of electricity and low-grade heat, Dr. Hieronymus developed an estimate of the potential market for the system by geographic area.
- For the U.S. Environmental Protection Agency (EPA), he was the principal investigator in a series of studies that forecasted future supply availability and production costs for various grades of steam and metallurgical coal to be consumed in process heat and utility uses.

Dr. Hieronymus has been an invited speaker at numerous conferences on such issues as market power, industry restructuring, utility pricing in competitive markets, international developments in utility structure and regulation, risk analysis for regulated investments, price squeezes, rate design, forecasting customer response to innovative rates, intervener strategies in utility regulatory proceedings, utility deregulation, and utility-related opportunities for investment bankers.

Prior to rejoining CRA in June 2001, Dr. Hieronymus was a Member of the Management Group at PA Consulting, which acquired Hagler Bailly, Inc. in October 2000. He was a Senior Vice President of Hagler Bailly. In 1998, Hagler Bailly acquired Dr. Hieronymus's former employer, Putnam, Hayes & Bartlett, Inc. He was a Managing Director at PHB. He joined PHB in 1978. From 1973 to 1978 he was a Senior Research Associate at CRA. Previously, he served as a project director at Systems Technology Corporation and as an economist while serving as a Captain in the U.S. Army.

Summary of Generation and Purchases

NERC	RTO	Exelon (MW)		PSEG (MW)
MAAC	PJM	11,001		12,017
ECAR	PJM	-		1,946
MAIN	PJM	15,340		0
NPCC	ISO-NE	601		967
NPCC	NYISO	-		761
WECC	CAISO	-		443
SPP	SPP	795		-
ERCOT	ERCOT	3,651	1/	2,026
SERC		1,755	1/	-
MAIN		713		-
Total		33,026	1/	18,160

1/ Exelon's 830 MW purchase from the Tenaska Frontier plant can be delivered into SERC or ERCOT. The purchase is shown in both SERC and ERCOT in this table, but the total adjusts for double-counting.

Exelon Generation Portfolio[1/]

NERC Region	Control Area	Unit Name	Primary Fuel Type	Total Capacity (MW)	Ownership Share	Purchases (Sales)	Net Interest (MW)
MAAC	PJM	Chester	Oil	39	100%		39
MAAC	PJM	Conemaugh	Coal	1,700	20.72%		352
MAAC	PJM	Conemaugh	Oil	11	20.72%		2
MAAC	PJM	Conowingo	Hydro	548	100.00%		548
MAAC	PJM	Cromby 1	Coal	144	100.00%		144
MAAC	PJM	Cromby 2	Oil/Gas	204	100.00%		204
MAAC	PJM	Croydon	Oil	384	100%		384
MAAC	PJM	Delaware	Oil	56	100%		56
MAAC	PJM	Delaware	Oil	2.7	100%		3
MAAC	PJM	Eddystone	Oil	60	100%		60
MAAC	PJM	Eddystone 1, 2	Coal	581	100%		581
MAAC	PJM	Eddystone 3, 4	Oil/Gas	760	100%		760
MAAC	PJM	Fairless Hills	Landfill Gas	60	100%		60
MAAC	PJM	Falls	Oil	51	100%		51
MAAC	PJM	Keystone	Coal	1,700	20.99%		357
MAAC	PJM	Keystone	Oil	10.8	20.99%		2
MAAC	PJM	Limerick	Uranium	2,268	100%		2,268
MAAC	PJM	Moser	Oil	51	100%		51
MAAC	PJM	Muddy Run	Hydro	1,070	100%		1,070
MAAC	PJM	Oyster Creek	Uranium	619	100%		619
MAAC	PJM	Peach Bottom	Uranium	2,224	50%		1,112
MAAC	PJM	Pennsbury	Gas	6	100%		6
MAAC	PJM	Richmond	Oil	96	100%		96
MAAC	PJM	Salem	Oil	38	42.60%		16
MAAC	PJM	Salem	Uranium	2,221	42.60%		946
MAAC	PJM	Schuylkill	Oil	166	100%		166
MAAC	PJM	Schuylkill	Oil	30	100%		30
MAAC	PJM	Schuylkill	Oil	2.8	100%		3
MAAC	PJM	Southwark	Oil	52	100%		52
MAAC	PJM	Three Mile Island 1	Uranium	786	100%		786
MAAC	PJM	Various NUGs	NUG			177	177
		Subtotal		15,941			11,001
MAIN	PJM	Braidwood	Uranium	2,362	100%		2,362
MAIN	PJM	Byron	Uranium	2,356	100%		2,356
MAIN	PJM	Dresden	Uranium	1,700	100%		1,700
MAIN	PJM	La Salle	Uranium	2,293	100%		2,293
MAIN	PJM	Quad Cities	Uranium	1,728	75.00%		1,296
		Subtotal		10,439			10,007
Purchases from Dominion							
MAIN	PJM	Kincaid	Coal			1,158	1,158
MAIN	PJM	State Line	Coal			515	515
		Subtotal				1,673	1,673

Exelon Generation Portfolio[1/]

NERC Region	Control Area	Unit Name	Primary Fuel Type	Total Capacity (MW)	Ownership Share	Purchases (Sales)	Net Interest (MW)
Purchases from Merchant Plants in MAIN							
		Subtotal				3,660	3,660
		Subtotal PJM				**5,333**	**26,341**
Other Generation and Purchases							
SPP	CSWS	Cogentrix Jenks (Green Country)	Natural Gas			795	795
SERC	Southern	Tenaska Heard County	Natural Gas			925	925
SERC/ERCOT	Entergy/ERCOT	Tenaska/Frontier	Natural Gas			830	830
MAIN	IP	Clinton (AmerGen)	Uranium	1,026	100% [2/]	(400)	713
ERCOT	ERCOT	La Porte 1-4	Natural Gas		[3/]	160	160
ERCOT	ERCOT	Mountain Creek 2-8	Natural Gas	890	100% [3/]		890
ERCOT	ERCOT	Handley	Natural Gas	1,421	100%		1,421
ERCOT	ERCOT	AES Wolf Hollow	Natural Gas			350	350
NPCC	ISO-NE [4/]	Framingham	Oil	29	100%		29
NPCC	ISO-NE [4/]	New Boston	Gas	380	100%		380
NPCC	ISO-NE [4/]	New Boston	Gas	20	100%		20
NPCC	ISO-NE [4/]	West Medway	Oil	165	100%		165
NPCC	ISO-NE [4/]	Wyman Unit	Oil	611	6%		36
		Subtotal					6,714
		Total					**33,055**

Notes:

[1/] Generation data from EIA-411 (2004) and EIA-860 (2004), Exelon Corp. 10-K filed March 2004, and company sources. In most instances, capacity represents summer ratings.

[2/] Under long-term contract (through 2006) to Illinois Power.

[3/] These assets are dedicated to sales within ERCOT.

[4/] Effective June 2004, other former Exelon New England assets were sold to Boston Generating and are not reported here.

PSEG Generation Portfolio

NERC Region	Control Area	Unit Name	Primary Fuel Type	Total Capacity (MW)	Ownership Share	Purchases (Sales)	Net Interest (MW)
MAAC	PJM	Bayonne 1-2	Oil	42	100.0%		42
MAAC	PJM	Bergen 1-3 and New	Gas	1,224	100.0%		1,224
MAAC	PJM	Burlington	Gas	389	100.0%		389
MAAC	PJM	Burlington 8-11	Oil	168	100.0%		168
MAAC	PJM	Conemaugh	Coal	1,700	22.50%		383
MAAC	PJM	Conemaugh	Oil	11	22.50%		2
MAAC	PJM	Conemaugh Dam	Hydro	17	50.00%		8
MAAC	PJM	Edison 1-3	Gas	504	100.0%		504
MAAC	PJM	Essex 9-12	Gas	617	100.0%		617
MAAC	PJM	Hope Creek 1	Uranium	1,049	100.0%		1,049
MAAC	PJM	Hudson 1	Gas	383	100.0%		383
MAAC	PJM	Hudson 2	Coal	608	100.0%		608
MAAC	PJM	Kearny	Gas	300	100.0%		300
MAAC	PJM	Kearny 12	Oil	175	100.0%		175
MAAC	PJM	Kearny 7-8	Oil	155	100.0%		155
MAAC	PJM	Kearny 9-10	Gas	134	100.0%		134
MAAC	PJM	Keystone	Coal	1,700	22.83%		388
MAAC	PJM	Keystone	Oil	10.8	22.83%		2
MAAC	PJM	Linden CC	Gas	1,186	100.0%		1,186
MAAC	PJM	Linden 5-6	Gas	160	100.0%		160
MAAC	PJM	Linden 7-8	Gas	156	100.0%		156
MAAC	PJM	Mercer 1-2	Coal	648	100.0%		648
MAAC	PJM	Mercer 3	Oil	129	100.0%		129
MAAC	PJM	National Park 1	Oil	21	100.0%		21
MAAC	PJM	Peach Bottom 2-3	Uranium	2,224	50.0%		1,112
MAAC	PJM	Salem 1-2	Uranium	2,221	57.4%		1,275
MAAC	PJM	Salem 3	Oil	28	57.4%		16
MAAC	PJM	Sewaren 1-4	Gas	453	100.0%		453
MAAC	PJM	Sewaren 6	Oil	129	100.0%		129
MAAC	PJM	Yards Creek	Hydro	400	50.0%		200
ECAR	PJM	Lawrenceburg	Gas	1,096	100.0%		1,096
ECAR	PJM	Waterford	Gas	850	100.0%		850
		Subtotal		18,887			13,963
NPCC	ISO-NE	Bridgeport Harbor	Coal/Oil	503	100.0%		503
NPCC	ISO-NE	Bridgeport Harbor	Oil	10	100.0%		10
NPCC	ISO-NE	New Haven Harbor	Oil/Gas	448	100.0%		448
NPCC	ISO-NE	Bridgewater	Biomass	16	40.0%		6
		Subtotal		977			967
NPCC	NYISO	Albany/Bethlehem	Gas	761	100.0%		761
		Subtotal		761			761
ERCOT	ERCOT	Guadalupe	Gas	1,000	100.0%		1,000
ERCOT	ERCOT	Odessa	Gas	1,026	100.0%		1,026
		Subtotal		2,026			2,026

PSEG Generation Portfolio

NERC Region	Control Area	Unit Name	Primary Fuel Type	Total Capacity (MW)	Ownership Share	Purchases (Sales)	Net Interest (MW)
WECC	CAISO	Bay Area I	Pet coke	21	50.0%		11
WECC	CAISO	Bay Area II	Pet coke	211	50.0%		106
WECC	CAISO	Bay Area III	Pet coke	21	50.0%		11
WECC	CAISO	Bay Area IV	Pet coke	21	50.0%		11
WECC	CAISO	Bay Area V	Pet coke	21	50.0%		11
WECC	CAISO	Hanford	Pet coke	27	50.0%		14
WECC	CAISO	Hanford Peaker	Gas	95	75.0%		71
WECC	CAISO	Henrietta Peaker	Gas	97	75.0%		73
WECC	CAISO	Tracy	Biomass	21	35.0%		7
WECC	CAISO	Tracy Peaker	Gas	171	75.0%		128
WECC	CAISO	SEG III	Solar	30	9.0%		3
		Subtotal		736			443
		TOTAL		23,387			**18,160**

Data and Methodology for Competitive Analysis Screen

I. INTRODUCTION

This document describes the data required to conduct the market power analyses as well as the source and methodology used to collect and input the necessary data. The delivered price test requires estimating the generating resources for each of the potential suppliers in the model, specifying the transmission network that these suppliers can use to reach the relevant destination market, and the destination market price. All of the relevant data used in the analyses are included in workpapers.

CRA's proprietary Competitive Analysis Screening model ("CASm") was used to conduct the Commission's delivered price test.[1] This model was used to calculate structural indicators according to the delivered price test framework, as required by the Federal Energy Regulatory Commission ("Commission"). A detailed description of CASm is provided in Exhibit J-5. Briefly, CASm is a linear programming model developed specifically to perform the calculations required in undertaking the delivered price test and has been submitted in a number of proceedings before the Commission, as well as in state proceedings. The model includes each potential supplier as a distinct "Node"[2] or area that is connected via a transportation (or "pipes") representation of the transmission network. Each path in the network can be assigned its own non-simultaneous limit and cost. Flow restrictions can be applied across sets of paths to capture any relevant simultaneous limits. Potential suppliers are allowed to use all economically and physically feasible paths to reach the destination market. In instances where more generation meets the economic criterion of the delivered price test than can actually be delivered on the transmission network, scarce transmission capacity is allocated based on a proration method, described below.

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1 CASm was originally developed under the direction of CRA employees while under the employ of other companies.

2 The term "Nodes" is used in CASm to denote control areas or regions in which load, generation or transmission assets are aggregated.

II. IMPLEMENTATION OF HORIZONTAL ANALYSIS

A. Regions Modeled

The list of entities included in the model (and corresponding abbreviations used in other exhibits) is included in workpapers. The following regions were included in the analysis:

- PJM Interconnection ("PJM")[3]
- Midwest Independent Transmission System Operation ("MISO")
- New York Independent System Operator ("NYISO")

The model includes all significant generation and load sources in each region, including traditional utilities, Independent Power Producers ("IPPs"), Non-Utility Generators ("NUGs"), municipal utilities and cooperatives. These are generally modeled as individual "nodes" in the model. In modeling MISO, no distinction is made for the former control areas within MISO; in other words, there effectively is assumed to be no transmission constraints within MISO, and a single transmission rate applies.[4] This treatment is of little consequence to the results of my analysis, since imports from MISO are in any event limited by a simultaneous import constraint into PJM. In the past, the Commission has limited potential suppliers to within "four wheels" of the relevant destination market.[5] With the introduction of ISOs and RTOs, this concept is no longer applicable, particularly in the context of this merger. Instead, it is more than sufficient to include as potential suppliers PJM's first-tier suppliers (i.e., entities within MISO and NYISO).

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3 Including, for this purpose, Dominion Virginia Power, which is expected to be integrated into PJM during 2005.

4 Moreover, these significantly reduces the complexity of modeling the transmission system within MISO, given that MISO now uses flowgates rather reporting Available or Total Transfer Capability (ATC/TTC).

5 For example, in *FirstEnergy*, the Commission limited the number of wheels "a supplier could reasonably travel to reach the destination market," recognizing that "[m]ore distant suppliers would face considerable losses and transmission costs." There, the Commission limited the potential suppliers to those within four wheels. *Ohio Edison et al.*, 80 FERC ¶61,039 (1997).

B. Estimating Supply Resources for Each Node

Supply curves, consisting of a price and quantity for each node, are developed and entered into CASm.

1. Supply Capacity

The main source for data on generating plant capability is the Form EIA-411. Publications dated April 2004 were used, supplemented by earlier editions as necessary.[6] The EIA-411 provides data on summer and winter capacity, planned retirements and additions and jointly-owned units. For jointly-owned plants, shares were assigned to each of the respective owners. Summer ratings were used for the summer and shoulder periods and winter ratings for the winter period. The data were adjusted to reflect planned retirements and capacity additions through 2006, as detailed in the EIA-411 forms.

The capacity representing shares of jointly-owned units typically is treated as if the shares reside at the physical location of each of the co-owners.[7]

Purchases and Sales

Where data are available, each supplier's generating resources were adjusted to reflect long-term (one-year or more) generation purchase and sales.[8] Available data are based on publicly available information, such as FERC Form 1 and EIA Form 412 filings (or databases

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6 Increasingly, many of the EIA-411 reports do not include data at the level of generating unit detail such as is required for input into the analysis. However, the Annual Generator Report, EIA-860 has generally equivalent information.

7 In analyzing the ICAP (as opposed to the energy) market, I considered certain generation units jointly owned by affiliates of DPL, AEP, and Cinergy, as eligible as PJM capacity. Some of these units were deemed "deliverable" capacity by PJM and others were deemed "deliverable" capacity by MISO. I treated the capacity of those units deemed "deliverable" in the PJM market as located within PJM, but with the appropriate shares of the capacity allocated among DPL, AEP and Cinergy.

http://www.pjm.com/markets/market-integration/downloads/documentation/20041018-aep-dayton-final-deliverability-results.xls

8 This treatment does not include requirements contracts.

based on these forms), Form EIA-411, individual utility resource plans and NERC's Electricity Supply and Demand ("ES&D") database.

To the extent a utility has sold energy under a long-term agreement, ownership over that resource is assumed to pass to the buyer.[9] Accordingly, generation ownership was adjusted to reflect the transfer of control by assuming that the sale resulted in a decrease in capacity for the seller and a corresponding increase in capacity for the buyer. Consistent with guidance provided in Appendix A, it was assumed that system power sales were comprised of the lowest-cost supply for the seller unless a more representative price could be identified.[10] To the extent that long-term sales could be identified specifically as unit sales, the capacity of the specific generating unit was adjusted and the variable element of the purchase price attributed to the sale was the variable cost of the unit. The dispatch price for system purchases was based on the energy price reported for long-term purchases in the FERC Form 1 where such purchases could be identified and a variable cost price determined.[11]

New Entry

Generating plants that are already under construction and scheduled to enter service by 2006 are included in my analysis. There are relatively few such units included in my analysis, and they are identified in workpapers. Identification of these units was based on a variety of publicly-available data sources, including Platts, EIA, company websites and regulatory filings.

Generating Unit Availability

Since the delivered price test is intended to evaluate energy products, the capacity (in MWs) reported in the Form EIA-411 was de-rated to approximate the actual availability of the units in each period. That is, it was assumed that generation capacity would be unavailable

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9 Consistent with this assumption, NUGs were assumed to be under the control of the purchasing utility, except in specific circumstances, as with PSE&G, as described in my testimony.

10 [T]he lowest running cost units are used to serve native load and other firm contractual obligations" (Appendix A, p. 11). The lowest-cost supply that was available year-round (i.e., excluding hydro) was used.

11 In instances where the purchases could not be matched with FERC Form 1 data, the dispatch price was estimated.

during some hours of the year for either (planned) maintenance or forced (unplanned) outages. Data reported in the NERC Generating Availability Data System ("GADS") was used to calculate the "average equivalent availability factor" to estimate total outages, and the "average equivalent forced outage rate" to estimate forced outages for fossil and nuclear plants.[12] Scheduled maintenance was assumed to occur only during the non-peak (shoulder) seasons and forced outages were assumed to occur uniformly throughout the year.

In addition the thermal unit availability, hydro unit availability and generation is specified for each time period. For each of the time periods analyzed, hydro capacity factors have been assigned to each unit based on historical operation. Capacity factors for hydro units were based on most recent 5 years of Form 759 monthly generation data, reported maximum capacities, and, where necessary assumptions regarding minimum capacity (assumed to be 15 percent of maximum if no data is available). Units were assumed to be at full generating capacity during super peak periods in each season and at minimum capacity during all off-peak periods. Any remaining generation was assumed to occur in the base peak period for each season. If this methodology resulted in either too much or too little being generated in each season, the generation was adjusted accordingly. A similar methodology was used to develop the seasonal generation of pumped storage units.

This treatment of generating availability is designed to account for the fact that resource availability changes by season. It is consistent with how the time periods evaluated were defined (based on similar load hours in each season, rather than by similar load hours for the entire year).

2. Supply Cost

In calculating the supply curves, supply from each unit was assumed to be available at any price above its incremental cost (the delivered price test assumes supply is economic if its cost is up to 105% of the competitive market price). The incremental cost is calculated by multiplying the fuel cost for the unit by the unit's efficiency (heat rate) and adding any additional

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[12] These data were supplemented, where necessary, by data from other public sources such as other NERC publications and Electric Power Research Institute ("EPRI").

variable costs that may apply, such as costs for variable operations and maintenance and costs for environmental controls.[13]

Data were taken from the following sources:

- Heat Rates – EIA Form 860, supplemented by data reported in Platts' PowerDat database. (Note that the most recently available data from the Form 860 date back to 1995.)

- Fuel Costs – FERC Form 423. Unit-specific dispatch costs were derived from fuel cost history and projections of fuel price escalation. Data on spot or interruptible fuel prices as reported in FERC Form 423 from a recent 12-month period served as the base fuel costs for each unit. If a spot price was not available, I assigned the unit a regional average spot price from a report derived from 423 data published by the EIA: *The Cost and Quality of Fuels at Electric Utility Plants*. In all cases, commodity fuel costs were assumed to escalate to 2006 at rates presented in recent forecasts by the EIA. With the significant escalation in Appalachian coal prices recently, I modified my approach slightly with respect to coal. I analyzed the source of coal to the relevant regions, and then used historical and forecast coal prices to estimate a forecasted delivered cost of coal to generators in PJM and MISO.

- Variable O&M – \$1/MWh for gas and oil steam units, \$3/MWh for scrubbed coal-fired units and \$2/MWh for other coal-fired units (generic estimates based on trade and industry sources).[14] Additional Variable O&M adders for other unit types are shown in my workpapers.

- Environmental Costs – All units covered by Phase II of the Clean Air Act Amendments of 1990 (CAAA) are assessed a variable dispatch adder to cover costs associated with SO2 emissions. This unit-specific cost is calculated using the SO2 content of fuel burned at the unit as reported in FERC Form 423 (adjusting for emissions reduction equipment at the facility) and an SO2

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13 For NUGs, the incremental costs were estimated based on the energy price reported in relevant regulatory filings, if available. Otherwise, NUGs were assumed to be must-run and the variable costs set to zero. New merchant capacity and cogeneration capacity included in the analysis was priced assuming an average full-load heat rate of 10,000 Btu/kWh for combustion turbines and 7,000 Btu/kWh for combined cycle plants. These values were derived from an evaluation of existing technology. Variable O&M costs for new units are assumed to be the same as for existing units.

14 As noted, these variable O&M costs are generic estimates by plant type and do not necessarily match actual individual unit O&M costs. Notably, variable O&M accounts for a minor portion of the dispatch costs used in the analysis, and, importantly, the specific O&M assumption tends not to alter the merit order of the generic types of generation.

allowance cost of $700/ton for 2006.[15] In addition to SO2, the unit dispatch costs also reflect the impact of existing NOx trading programs in the Northeast (OTR).[16] Unit-specific data on NOx rates (lbs/mmBtu) were taken from the EPA's "2000 Acid Rain Program Emission Scorecard."[17] The NOx allowance price for the OTR was assumed to be $3,350/ton, consistent with the OTR allowance market price index reported by the Environmental Protection Agency.

C. Transmission Network

Appendix A specifies that the transmission system be modeled on the basis of inter-control area ATCs or TTCs using transmission prices that are based on transmission providers' maximum non-firm OATT rates except where lower rates could be clearly documented. Given the specific circumstances of this merger, and the focus of the merger's effects on PJM markets, I modeled the transmission network as shown in Exhibit J-6.

1. Simultaneous Imports

Limits were placed on the amount of capacity that could be transferred over the transmission network by simultaneous import limits ("SIL"), and, in some instances by interface limits within the simultaneous limit construct.

For imports into PJM East, a SIL of 7,300 MW was assumed, based on a study conducted by PSEG's transmission engineering group,[18] and generation in the rest of PJM Pre-2004 competed for the limited transmission into PJM East.

A 4,600 MW SIL was used for imports into PJM Pre-2004, based on the maximum level of imports in 2003 for the capacity market.[19] When analyzing the PJM East market, the 4,600

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15 SO2 emissions are from FERC Form 423 for calendar year 2003 and SO2 costs of $700 was taken from Evolution Markets LLC's Monthly Market Update - SO2 Markets, November 2004.

16 NOx rates and allowance price ($3,350/ton) were derived from EPA's 2000 Acid Rain Program Emission Scorecard and Evolution Markets LLC's Monthly Market Update - NOx Markets, November 2004.

17 In cases where unit-specific data were not available, such as for new capacity, the following boiler level assumptions were applied, based on the unit's fuel type: Coal – 0.4; Oil – 0.2; Natural Gas – 0.1.

18 The workpapers for this study are included in my workpapers, filed as Critical Energy Infrastructure Information ("CEII").

MW SIL was used to limit flows into PJM Pre-2004, and the 7,300 MW SIL to limit flows into PJM East.

A SIL of 7,500 MW was used for imports into Expanded PJM, based on a study conducted by PJM.[20] When analyzing the PJM East market, the 7,500 MW SIL limited flows into Expanded PJM, the 4,600 MW SIL limited flows into PJM Pre-2004, and the 7,300 MW SIL limited flows into PJM East. When analyzing the PJM Pre-2004 market, the 7,500 MW SIL was applied to flows into Expanded PJM, and then the 4,600 MW SIL was applied to flows into PJM Pre-2004.

2. Transmission Rates

The Commission's Appendix A guidelines implicitly assume a depiction of the transmission system wherein control area to control area transactions occur using each of the relevant control area's Open Access (Order 888) tariffs. Appendix A also instructs applicants to model any applicable discounts that are systematically available, and to account for regional transmission organizations as they arise.

In implementing transmission rates into the analysis, regardless of the transmission regime, I typically have assumed that transmission charges would be incurred for the transmission system where the generator is located and for wheeling the power through intermediate systems, but not for the destination market. No transmission charge is included for the transmission system in which the load is located. This has no impact on the analysis, since including this charge (the transmission charge included in the bundled rate of the transmission provider in the area where the customer is located, or the "zonal" or postage stamp charges in the

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19 *2003 State of the Market*, PJM Market Monitoring Unit, March 4, 2004, pages 123. "An average of 3,819 MW of capacity resources was imported into the PJM and an average of 1,664 MW was exported (delisted) for an average net import of 2,155 MW of capacity resources during the period. The maximum export (delist) was 2,457 MW, while the maximum import was 4,638 MW."

20 "Simultaneous PJM Import Capability", Document prepared by System Operations Division – Transmission, September 8, 2004, and posted on OASIS. http://www.pjm.com/markets/market-integration/downloads/documentation/20040909-simultaneous-pjm-import-capability.pdf

case of an RTO) would symmetrically raise the delivered cost for each supply to reach the destination market by the same amount. Thus, the relative economics would not be impacted.[21] Losses are assessed for each wheel incurred along the path to deliver power to the destination market but are not added for the final wheel into the destination market.

For my analysis of relevant PJM markets, I assumed that there was no transmission costs for deliveries within PJM or MISO. I assessed a loss of 2.8 percent for imports from MISO into PJM. I would note that my results are essentially invariant to these inputs, which is not surprising since these charges are generally applied to all suppliers in the model and the costs are relatively insignificant in determining whether a potential supplier is included in the market.

D. Allocation of Limited Transmission

Appendix A notes that there are various methods for allocating transmission, and that applicants should support the method used.[22] There are two basic approaches to allocating limited transmission capacity: economic and pro rata. Under an economic allocation, available transmission is assigned on the basis of the cost of the capacity (energy) competing to use limited transmission capability. The lowest cost capacity is assumed to have a priority in using the transmission. Higher cost generation is excluded, despite its having costs below 105 percent of the destination market price. In contrast, pro rata methods of allocation treat all generation that meets the delivered price test equally in allocating scarce transmission.

The paradigm lying behind the proration required by the Order No. 592 delivered price test (whether economic or pro rata methods are used) can be likened to a tree, for which the root is the destination market. At the furthest extremes are small branches, each one of which is connected to a single larger branch and so on until the trunk and root are reached. There is no

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21 Likewise, distinctions between "bundled and unbundled" transactions, which affect the price paid for the final delivery of power, do not affect the relative delivered prices of competing supplies.

22 Order No. 592, ¶ 31,044 at 30,133. ("In many cases, multiple suppliers could be subject to the same transmission path limitation to reach the same destination market and the sum of their economic generation capacity could exceed the transmission capability available to them. In these cases, the ATC must be allocated among the *potential* suppliers for analytic purposes. There are various methods for accomplishing this allocation. Applicants should support the method used.")

ambiguity concerning the path. Hence, at every node (joining with a large branch), all of the capacity that can access the limited capacity of the branch can be calculated; each small branch's capacity is reduced proportionately to the capacity of the branch. This can be repeated successively, moving inward to the destination market.

Even taking into account the simplifications required by a "transportation" representation of transmission, real world transmission systems are more complex. The "small branch" distant utilities have multiple paths by which a destination market can be reached. In some cases, paths may first be in a direction away from the destination market, looping around onto another path to it. An analysis that takes this important complexity into account is computationally very difficult. Allocation methods differ partly in terms of how the problem is simplified in order to make computation tractable.

The major drawback of using an economic allocation is that it tends to continually reallocate the same low cost energy, principally hydro and nuclear energy (and non-dispatchable NUG capacity) over and over to each destination market in the Economic Capacity measure. This occurs partly because Appendix A does not take into consideration the opportunity cost of supplying alternative markets to the destination market being analyzed,[23] but primarily because each destination market is analyzed separately. This allows the same low cost supplies to be allocated to each of the destination markets. While this is not wholly inappropriate, since the purpose of Appendix A is to measure potentially competing supply to each destination market, it does mean that the very low cost supplies can travel far and wide and occupy a highly disproportionate share of available transmission. This repeated allocation of the same energy is particularly troublesome given the large area involved in the analysis in the instant case. This flaw is less severe in the Available Economic Capacity measure, where the native load obligations absorb each control area's lowest cost resources.

For purposes of this analysis, limited transmission capacity was allocated using a "squeeze-down" method, so-named because it seeks to prorate capacity at each node and is the

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[23] Indeed, if opportunity costs were taken into account, and one was considering a regional dispatch, available transmission capacity appropriately would be allocated on the basis of economics.

likely closest approximation to what the Commission applied in the FirstEnergy merger[24] that is computationally feasible. Under this method, shares of available transmission are allocated at each interface, diluting as they get closer to the destination market. When there is economic supply (i.e., having a delivered cost less than 105 percent of the destination market price) competing to get through a constrained transmission interface into a control area, the transmission capability is allocated to the suppliers in proportion to the amount of economic supply each supplier has outside the interface.

Shares on each transmission path are based on the shares of deliverable energy at the source node for the particular path being analyzed. The calculations start at the outside of a network defined with the destination market as its center and end at the destination market itself. A series of decision rules are required to accomplish this proration. The purpose of these decision rules is limited to assigning a unique power flow direction to each link for any given destination market analysis. Once the links are given a direction, the complex network can be solved. CASm implements a series of rules to determine the direction of the path. The first rule (and the one expected to be applied most frequently) is based on the direction of the flow under an economic allocation of transmission capacity. Other options take into consideration the predominant flow on the line based on desired volume (the amount of economic capacity seeking to reach the destination market, the number of participants seeking to use a path in a particular direction and the path direction that points toward the destination market.

The model proceeds to assign each supplier at each node a share equal to its maximum supply capability. At each node, "new" suppliers (those located at the node outside of the next interface) are given a share equal to their supply capability and the shares of more distant suppliers (those who have had to pass through interfaces more remote from the destination market in order to reach the node) are scaled down to match the line capacity into the node.

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[24] *Ohio Edison Company, et al.*, 80 FERC ¶ 61,039 (1997). ("When there was more economic capacity (or available economic capacity) outside of a transmission interface than the unreserved capability would allow to be delivered into the destination market, the transmission capability was allocated to the suppliers in proportion to the amount of economic capacity each supplier had outside the interface.")

Ultimately, the shares at the destination market represent the prorated shares of capacity that is both economically and physically feasible.

CASm's operation is the same in the horizontal and vertical applications with one exception, arising from how CASm's considers market participants when allocating transmission on a prorata basis. The prorata allocation of transmission capacity is modified for the vertical study in order to ensure that a prorata share of each fuel type (e.g., coal, gas, and oil) is delivered to the destination market. Without this modification, the gas-fired plants in Nodes outside the destination market would be allocated very little, if any, transmission capacity because base-load plant, with lower dispatch costs, would be allocated first by CASm.[25] For a standard horizontal study, this does not matter because the allocation of base-load plant versus gas-fired plant for the same owner is equivalent. For the vertical study, base-load plant is attributed to its actual owner, but gas-fired plant is attributed to the gas pipeline serving the plant. The modification to CASm is conservative and appropriate because otherwise gas-fired capacity would be underreported in the market.

III. IMPLEMENTATION OF VERTICAL ANALYSIS

A. Downstream Analysis

The relevant framework requires that the structure of downstream markets be analyzed using the same delivered price test methodology as in the horizontal market power analysis, but with gas-fired generation deemed to be controlled by (*i.e.*, is assigned to) its gas supplier rather than its owner.

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25 Specifically, by default CASm considers each Node as a single entity when calculating the amount of scarce transmission capacity that should be allocated to each participant, rather than evaluating each individual generating unit (or "tranche"). Thus, CASm does not distinguish between different tranches within a Node when solving and will generally dispatch the lowest cost resources.

There are a few thousand generating units in the Eastern Interconnection database that use natural gas as their primary fuel source. Gas connections for these units are determined from a variety of sources:[26]

- A Directory of Natural Gas Customers published by Energy Planning, Inc. provides the natural gas transportation information for about half of the electric generating units.
- Databases published by Platts (e.g., POWERdat and POWERmap) provide the locations of the power plants, pipelines, and local distribution companies. In some cases, the locations of the gas generating units that are not included in Platts' database are determined from other public sources.
- Brown's Directory of North American Gas Companies, which identifies LDCs.
- Applicants have provided information for the generating units served by their LDCs.

This information is used to attribute the generation of the natural gas units to the pipeline companies, following a series of decision rules:

- If a power plant is directly connected to a pipeline, the capacity of the plant is attributed to the pipeline, unless the pipeline is jointly owned. If the pipeline is jointly owned, the capacity is conservatively attributed to the owner with the largest ownership share.
- If the power plant is directly connected to multiple pipelines owned by other companies, the plant's capacity is divided among equal shares to the pipelines that are connected.
- If the power plant's most likely connection is determined by examination of maps, the entire capacity of the plant is attributed to that pipeline. If the pipeline connection cannot be identified by examining maps, the capacity is assigned to the electricity owner.
- If the power plant is directly connected to an LDC that has only a single pipeline connection, the capacity of the plant is attributed to the pipeline serving the LDC.

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26 To the extent generators cannot be located by using any of the available sources, they were not attributed to any pipeline, i.e., they remained with their owner.

- If there is no information on the pipeline(s) serving an LDC or if there are multiple pipelines serving the LDC, the capacity is assigned to the electricity owner.
- For generation served by Applicants' LDCs, the capacity is assigned to Applicants.

Once the natural gas-fired units are attributed to the pipeline companies, the Economic Capacity analysis proceeds in a similar fashion to the horizontal (generation) analysis.

B. Upstream Analysis

The analysis of the upstream market requires that the structure of control of transportation capacity be examined. For this purpose, control of gas transportation pipelines is allocated to holders of firm capacity rights with any unsubscribed capacity allocated to the pipeline owner.

For a given geographic market definition, there are three primary steps required to determine market concentration. The first is to identify the physical pipeline assets serving the market. The second is to identify the entities that own or control that capacity. The third is to allocate the regional pipeline capacity to its rights holders and calculate market concentration.

The EIA database of interstate pipeline capacity and flows "at state borders" is the starting point for identifying pipelines serving each market. For PJM East, pipelines flowing from outside the target region into the market area were identified. Pipeline and service territory maps were used to refine the definition of pipelines to be included. The aggregate capacity of the pipelines so identified represents the total supply for the market.

Next, pipeline capacity is allocated to pipeline customers who have firm capacity rights under long-term agreements. These firm customers have the first call on the pipeline capacity into a region and retain the option of selling their rights to a third party (*e.g.*, through capacity release) should conditions warrant. These customers are the suppliers of gas to that market (or are customers buying gas upstream of the pipeline) and thus direct or indirect competitors selling delivered gas into downstream markets. The primary source of information for identifying shippers with firm contractual rights is the Index of Customers (Form 549b) filed with the

Commission by interstate pipeline companies. The index provides a list of customers, contract volumes, rate schedule and delivery points.

The analysis is based on delivery point information to identify shippers with (delivery points in the market, and then allocating the total pipeline capacity into a market to firm customers with delivery points in the market. To the extent, the total of firm contracts is in excess of a pipeline's capacity into a market, capacity was allocated to parties with the largest amount of capacity under contract, resulting in a conservative (*i.e.*, more highly concentrated) estimate of market concentration. To the extent firm entitlements within and downstream of the market were less than capacity on a given pipeline, the remaining capacity was assumed to be controlled by the pipeline owner.

COMPETITIVE ANALYSIS SCREENING MODEL (CASm)

Charles River Associate's Competitive Analysis Screening model ("CASm") is designed to perform the calculations required in order to conduct a market power analysis under Appendix A of the FERC Merger Policy Statement ("Order No. 592" or "Appendix A").[1] The delivered price test specified in Appendix A requires an analysis of market concentration for a large number of markets under a number of different conditions. CASm facilitates this process by performing the required calculations.

The primary requirement of Appendix A is to assess potential suppliers to a market using a "delivered price test". This test involves comparing variable generation costs plus delivery costs (transmission rates, transmission losses and ancillary services) to a "market price." If the delivered cost of generation is less than 105 percent of the market price, the generation is considered economic. Economic generation is further limited to the amount that can be delivered into the market, given transmission capability and constraints.

CASm implements the prescribed delivered price test by determining -- for each destination market, for each relevant time period, and for each relevant supply measure -- potential supply to the destination market both pre- and post-merger. In effect, CASm determines the relevant geographic market by applying the delivered price test, based on the economics of production and delivery (transmission rates, transmission losses and ancillary services), and also based on the physical transmission capacity available to the competing suppliers on an open access basis. This requires a delivery route for the energy on the established transmission paths, each of which has a capability, transmission rate and transmission losses associated with it. CASm finds the supply that can be delivered to the destination market consistent with cost minimization and the delivered price test.

As a formal matter, CASm minimizes the production and transmission costs of supplying demand in the destination market. Any shortfall in demand is filled by a hypothetical generator located in the destination market that can produce an unlimited amount of energy at 105 percent of the market price. On this basis, any supplier who can profitably supply energy to the destination market will do so, to the maximum extent that their cost structure and the transmission system allow. This formulation ensures that no supplied generation is uneconomic; the hypothetical generator will undercut all such suppliers.

CASm determines pre- and post-merger market shares and calculates concentration (as measured by the Herfindahl-Hirschman Index, or HHI) and the change in HHIs.

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[1] CASm was developed under the direction of CRA employees while employed by Putnam, Hayes & Bartlett and PHB-Hagler Bailly, and has been used in analyzing numerous mergers and power plant acquisitions in proceedings before the Commission.

To undertake these analyses, CASm solves a series of scenarios involving a network of interconnected suppliers. By limiting suppliers based on the economics of generation and delivery, or by limiting the interconnections between those suppliers based on the transmission capability, each Appendix A analysis can be completed. CASm includes a simplified depiction of the transmission system, essentially a system of "pipes" with independent, fixed capacity between and among utilities.

The following sections describe:

- What data inputs are required to operate CASm
- How different analyses are undertaken in CASm
- What outputs CASm produces; and
- How CASm is implemented.

INPUT DATA

Market Participants

The largest element of the required data for CASm relates to individual market participants, which generally are utilities with both generating capacity and load obligations. In addition, some market participants may have load obligations but no generating capacity (e.g., transmission dependent utilities, or TDUs) or have generating capacity but no load obligations (e.g., merchant capacity). CASm regards all distinct market participants as having the ability to both supply and consume electricity. The particular circumstances of each analysis will determine the extent to which each activity is possible.

Nodes

In CASm, a node is a location where electricity is generated or consumed, or where it may "split" or change direction. All market participants are defined as having a unique node, and hence unique location in the transportation network. Total simultaneous import limits can be imposed at each node to mirror reliability restrictions.

Output Capability

Each market participant may have generating ability, which is defined generically in terms of any number of "tranches" of generation having both a quantity (MW) and dispatch cost ($/MWh). This output capability and cost may differ over time, for example because of planned and unplanned outage rates and fuel prices. CASm has a number of data inputs available for modifying the underlying physical availability of generating assets to get the relevant "supply curve" for any given model period.

Destination Market Prices

For each destination market, a prevailing market price is defined. The destination market price is used to calculate a threshold price that potential suppliers must meet to be included in the market for economic-based analyses (that is, the "delivered price test").

Interconnections

Interconnections represent the network that links market participants together. These interconnections are represented as a "transportation" network, where flows are specifically directed.

Lines

A line between two nodes in CASm may represent either a single line, or the combined effect of a number of lines. Each line has an upper limit on the flow, and losses may occur on the line. Since capacity on the line may represent physical limits less firm commitments, limits are allowed to be different, depending on the direction of the flow. Limits on the simultaneous flow on combinations of lines can be imposed to simulate the effect of loopflow or reliability constraints.

Scenarios

The final input area for CASm is related to scenario definition. Scenarios define which parties are considering merging, which load periods are relevant, and so on. In effect, the scenarios define a number of individual analyses to be performed, and how they should be compared to each other for reporting purposes.

Accounting for Ownership

It is sometimes necessary to merge the results for several nodes, or to split them, based on ownership changes between scenarios. CASm has a "report as" function that will merge the results of several nodes into a single one to correctly account for ownership. Also, CASm may "impute" all or part of any tranche in the supply curve of a node to any other node to account for shared ownership. This feature is used by CASm for vertical market analysis.

REQUIRED CALCULATIONS

Appendix A's delivered price test defines two different supply measures to evaluate:

- **Economic Capacity** is the amount of capacity that can reach a market at a cost (including transmission rates, transmission losses and ancillary services) no more than 105 percent of the destination market price.

- **Available Economic Capacity** is the amount of Economic Capacity that is available after serving native load and other net firm commitments with the lowest cost units.

For every analysis, the following process is undertaken:

First, a Linear Programming (LP) problem is solved. The LP construction is slightly different, depending on the underlying assumptions of each of the supply measures. CASm includes two options for allocating scarce transmission capacity. CASm has a "proration" option, which is called "squeeze-down". This is discussed in detail below. Another option is an economic allocation of limited transfer capability. Under this option, where available supply exceeds the ability of the network to deliver that capacity to the destination market, the least-cost supply is allocated the available transmission capacity.[2]

The final step involves calculating what can be delivered to the destination market, after accounting for line losses. CASm allocates total system losses amongst suppliers on the basis on how much they injected, and how far away (how many wheels) they are from the destination market.

Economic Capacity

For the Economic Capacity analysis, CASm solves an LP with the following form:

minimize cost for supplies at the destination market

subject to:

supply cost at destination < system lambda + 5%, for all suppliers

supply < quantity[3], for each node and tranche

supply + flows in = flows out + "demand", for each node

line flows are adjusted for losses, for all interconnections

line flows < available limit, for all interconnections (constrained network only)

sum over lines (flow * simultaneous factor) <= simultaneous limit, for all limits

sum over nodes (net injection * flowgate factor) <= flowgate limit, for all limits

The objective is slightly different when transmission capacity is to be prorated. The objective then becomes:

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2 CASm can be modified to apply different proration methods when appropriate for some analyses.

3 Available quantity may be modified. See discussion in the Output Capacity section.

minimize cost for supplies at the destination market; and

minimize divergence from calculated pro rata "share", for each supplier

And, where ownership imputation is being used, the following constraints are added:

sum over economic[4] tranches <= imputed share of economic tranches, for all owners at each imputed node

Available Economic Capacity

For the Available Economic Capacity analysis, CASm solves an LP with the following form:

minimize cost for supplies at the destination market

subject to:

supply cost at destination < system lambda + 5%, for all suppliers

supply < quantity (less native load), for each node and tranche

supply + flows in = flows out + "demand", for each node

line flows are adjusted for losses, for all interconnections

line flows < available limit, for all interconnections (constrained network only)

sum over lines (flow * simultaneous factor) <= simultaneous limit, for all limits

sum over nodes (net injection * flowgate factor) <= flowgate limit, for all limits

This is different from the economic capacity analysis only to the extent that potential suppliers are required to meet their load obligations prior to participating in the market.

When transmission capacity is to be prorated the objective becomes:

minimize cost for supplies at the destination market; and

minimize divergence from calculated pro rata "share", for each supplier

And, where ownership imputation is being used, the following constraints are added:

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4 Economic tranches are those that can deliver to the destination within 105% of the market price.

sum over economic tranches <= imputed share of economic tranches, for all owners at each imputed node

OUTPUTS

The primary output from CASm is a report that summarizes the results of different analyses. For each destination market, load period and FERC analysis type, CASm reports the following for both pre- and post-merger:

- Supplied MW
- Market Share
- HHIs

This report also shows the change in HHIs post-merger compared to pre-merger.

CASm also produces a transmission report that shows the detail of each node, and the injections and flows between them. Finally, a summary of the results for each market is also produced.

"SQUEEZE-DOWN" PRORATION

In the "squeeze-down" proration algorithm, prorated shares on each line are based on the weighted shares of deliverable energy at the source node for that line. As discussed more fully below, weighted shares at the destination market node are calculated by a recursive algorithm that starts at the "outside" of the network, then calculating shares on each line until it reaches the "middle". Specifically, where available supply exceeds the ability of the network to deliver that capacity to the destination market, suppliers are allocated shares at each node, and hence each outgoing line, based on the results of an algorithm that considers both supply and transfer capability at each node. Starting at the "outside" of the network, CASm calculates a share at each node that is based on a proportion of the incoming transfer capability (and the share of that capability allocated to each supplier), and the maximum economic supply available at that node. When the algorithm reaches the destination market, a total share of the incoming transfer capability has been determined.

This algorithm requires that all possible paths are simultaneously feasible, which, in turn, requires that each line be assigned a unique "direction". The steps of the proration algorithm include:

1. A C++ program enumerates all possible paths to the destination, the cost of transmission on each path and the maximum possible flow on the path. A "wheel limit", or maximum number of point-to-point links, may be imposed on paths.

2. The minimum "entry cost" for each supplier is calculated. This cost is the injection cost of the cheapest generator that has capacity for possible delivery to the destination.

3. Paths for which the entry cost plus the transmission cost are higher than 105% of the destination market price are rejected as being uneconomic.

4. To the extent remaining paths are not simultaneously feasible (because, for example, suppliers can seek to use the paths in both directions), a series of decision rules for determining the direction of the line are undertaken (in the following order):

    - Instructions can be manually input as to the chosen direction of a line.
    - Merger-case decisions should be consistent with base-case decisions.
    - The direction of the line as determined in an economic allocation of available transmission is applied.
    - The direction heading toward a destination market, if it is clear, is chosen.
    - The direction that retains the maximum potential volume-weighted flow on the line (calculated from the paths that depend on this line) is chosen.
    - The direction on which the maximum number of economic paths depend is chosen.

If these other options fail to reach a feasible solution, manual input will be required.

5. If there are simultaneous limits, they are checked for feasibility. All lines that have a worsening effect on a simultaneous constraint, given their defined flow direction, are checked against the simultaneous limit. If they would exceed the simultaneous limit if fully utilized, then their maximum capacity is prorated downwards in proportion to their respective limit participation factors. In this way, no set of targets will be produced that could not be delivered in a way that is feasible with the simultaneous limits.

6. Proration begins at nodes furthest from the destination market (where only exports, and no imports are being attempted). Suppliers at these nodes are assigned a "share" equal to their maximum economic supply capability.

7. Proration continues at the next set of nodes, that should consist only of nodes with inflows from "resolved" nodes from step 5. Suppliers at these nodes are assigned a "share" equal to their maximum economic supply capability. Suppliers from the "resolved" nodes have their shares scaled down to match the transmission capacity into the node.

8. To the extent an iteration of the algorithm does not resolve any additional nodes and the destination market has not yet been reached (i.e., a loop is detected), flow is disallowed from any unresolved node to the furthest and smallest node affected by a loop.

9. The proration has been completed when the destination market node has been resolved. At that point, the "shares" at the destination market represent the prorated shares of deliverable energy.

10. If ownership at a node is to be "imputed", or credited to another node, further proration targets are calculated. First, only those tranches that can deliver to the destination within 105% of the market price are considered. A factor representing the share each owner has of these economic tranches is calculated. For each owner, a constraint is calculated that limits the sum of injections attributed to that owner to be not more than that owner's "share" of the target calculated above. In this way, the proportion of ownership of economic capacity at a node is fairly reflected in the final solution outcome.

11. Injections for each supplier are "capped" at the calculated shares, and these injections are then checked for economic feasibility. While suppliers need not deliver their energy to the destination in exactly the way that their share was calculated, the solution is still both economically and physically feasible. The final solution represents the least-cost method of delivering these supplies.

CASM IMPLEMENTATION

CASm has been implemented using GAMS (Generalized Algebraic Modeling System), release 2.5. GAMS is a programming language which supports both data manipulation and calls to many mainstream mathematical modeling systems. The linear programming problems generated by CASm are solved by BDMLP. The path enumeration program has been written in Microsoft Visual C++ version 5.

Schematic of Relevant PJM Markets

PJM East

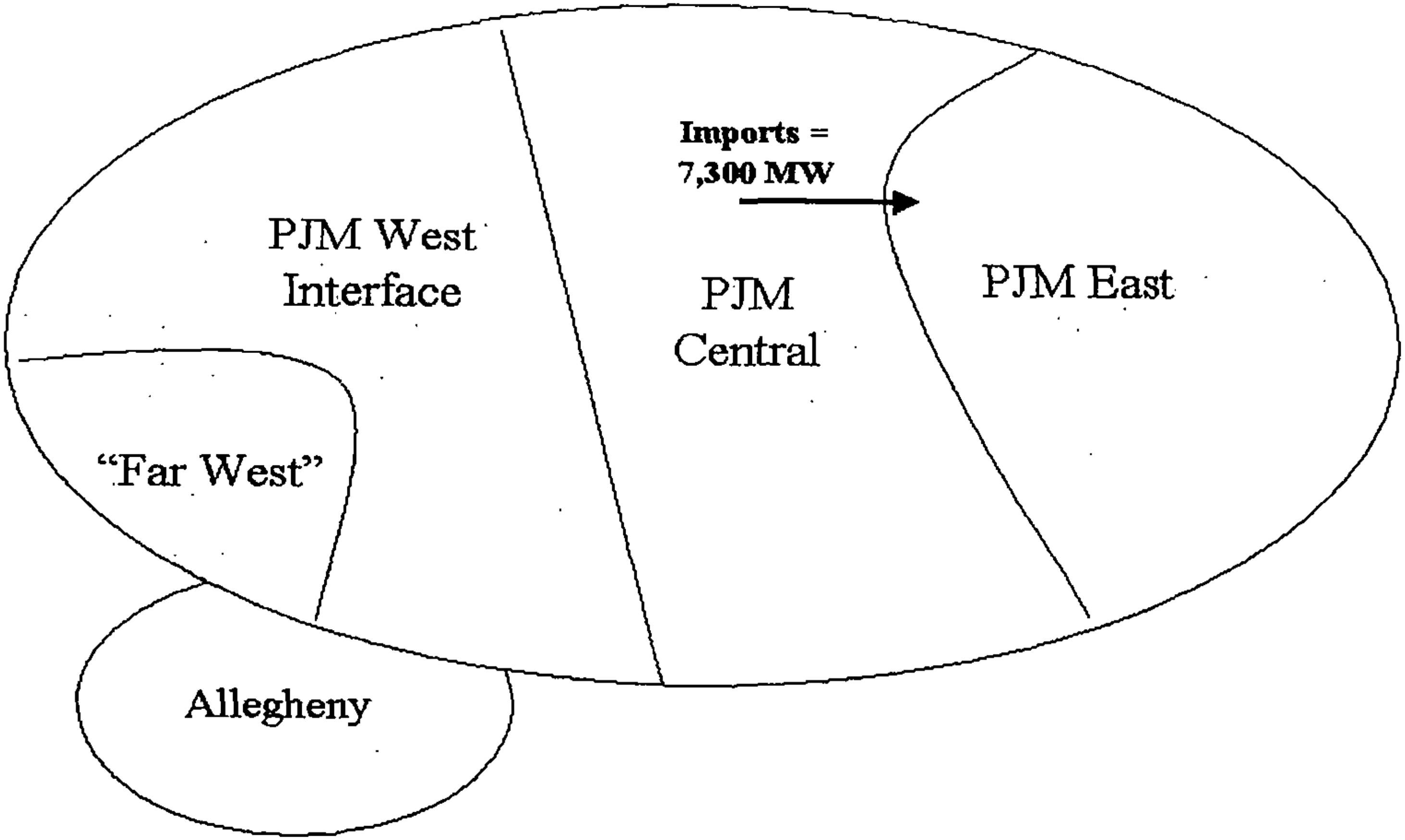
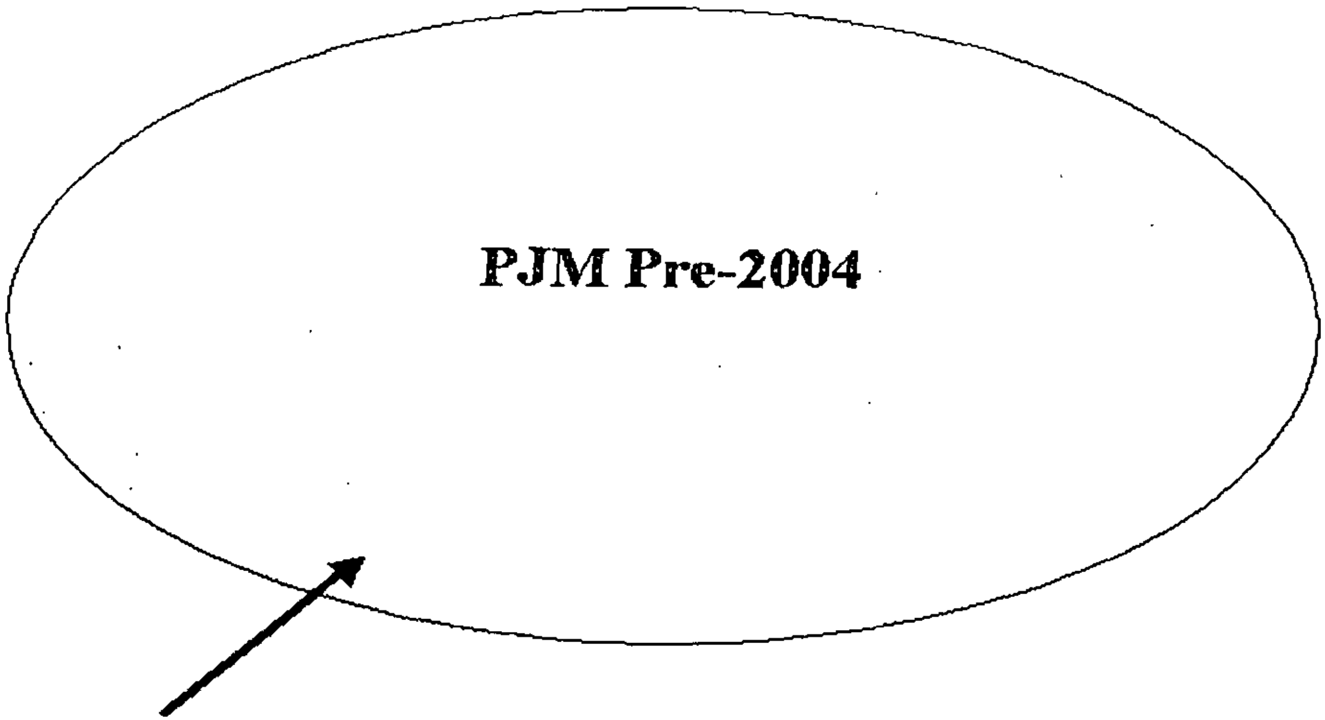


Exhibit J-6

Schematic of Relevant PJM Markets

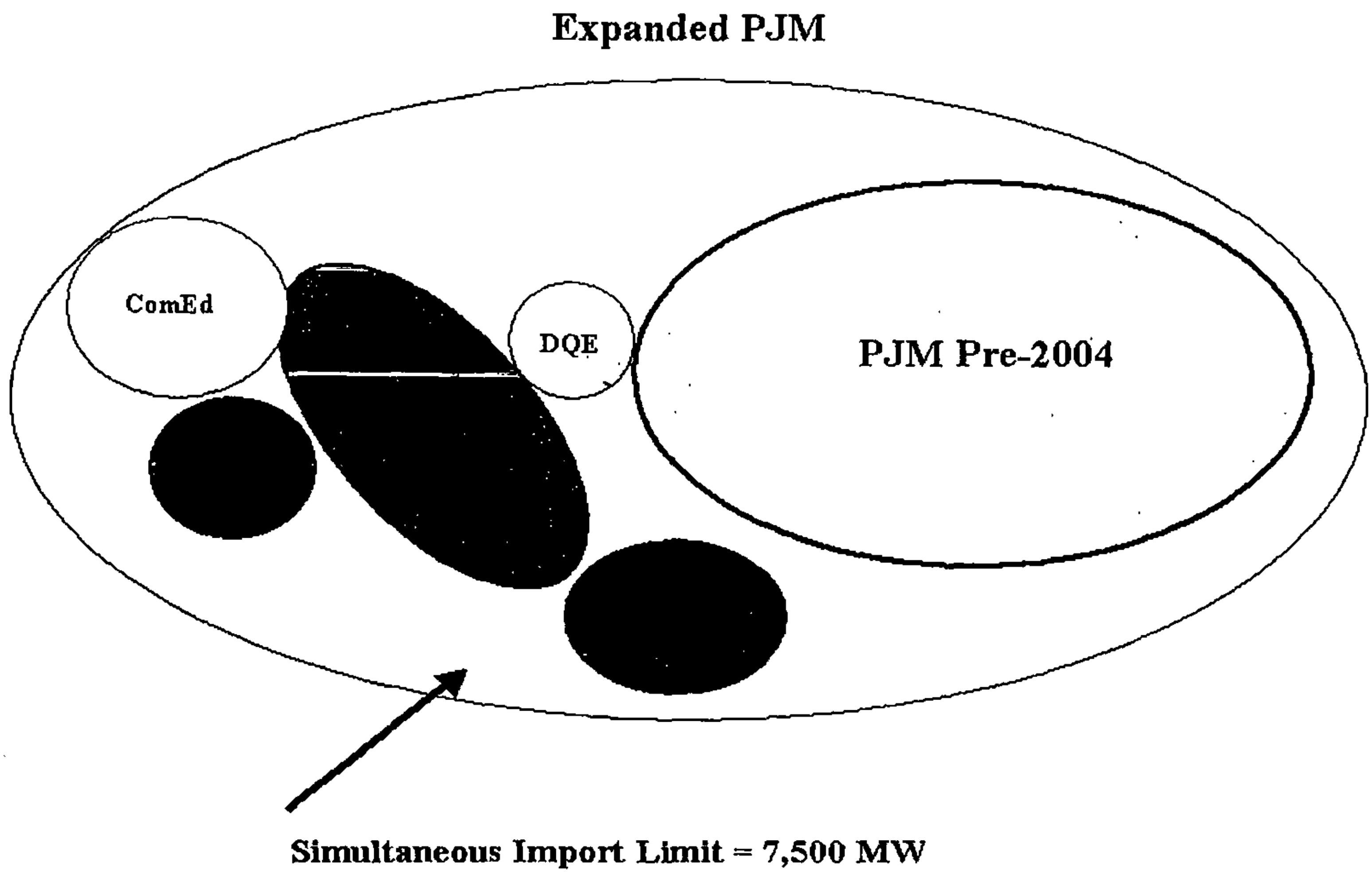
PJM Pre-2004



Simultaneous Import Limit = 4,600 MW

Exhibit J-6

Schematic of Relevant PJM Markets



Economic Capacity (Pre-mitigation)

		Pre-Merger						Post-Merger			
		Exelon		PSEG				EEG			
Period	Price	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	MW	Mkt Share	HHI	HHI Chg
PJM East											
S_SP1	$250	6,961	18.3%	9,658	25.4%	38,040	1,298	16,620	43.7%	2,227	929
S_SP2	$80	6,032	18.4%	7,757	23.7%	32,786	1,218	13,788	42.1%	2,088	870
S_P	$55	5,122	21.3%	5,957	24.8%	24,011	1,327	11,079	46.1%	2,385	1,058
S_OP	$25	4,887	30.7%	2,631	16.5%	15,919	1,477	7,518	47.2%	2,492	1,015
W_SP	$80	6,417	19.3%	7,796	23.4%	33,333	1,228	14,213	42.6%	2,128	900
W_P	$55	5,451	22.5%	5,770	23.8%	24,281	1,323	11,221	46.2%	2,390	1,067
W_OP	$30	5,167	26.6%	3,594	18.5%	19,398	1,324	8,761	45.2%	2,311	987
SH_SP	$65	4,896	20.4%	5,095	21.3%	23,958	1,187	9,991	41.7%	2,057	870
SH_P	$45	4,675	26.0%	2,935	16.3%	17,988	1,257	7,610	42.3%	2,105	848
SH_OP	$20	4,338	30.3%	2,051	14.3%	14,305	1,406	6,389	44.7%	2,276	870
PJM Pre-2004											
S_SP1	$250	10,508	13.6%	11,210	14.5%	77,273	896	21,718	28.1%	1,291	395
S_SP2	$80	9,545	13.8%	9,288	13.4%	69,380	885	18,834	27.2%	1,254	369
S_P	$55	7,976	14.6%	7,455	13.7%	54,517	971	15,431	28.3%	1,371	400
S_OP	$25	6,416	25.9%	3,189	12.9%	24,749	1,217	9,605	38.8%	1,885	668
W_SP	$80	9,899	14.1%	9,334	13.3%	70,238	883	19,233	27.4%	1,257	374
W_P	$55	8,299	15.1%	7,273	13.2%	54,932	968	15,571	28.4%	1,368	400
W_OP	$30	7,701	17.7%	4,946	11.4%	43,557	985	12,648	29.0%	1,386	401
SH_SP	$65	7,866	15.6%	6,263	12.4%	50,501	951	14,129	28.0%	1,337	386
SH_P	$45	6,936	17.2%	4,070	10.1%	40,251	1,004	11,006	27.3%	1,353	349
SH_OP	$20	5,472	26.4%	2,440	11.8%	20,715	1,206	7,912	38.2%	1,828	622
PJM Expanded											
S_SP1	$250	24,354	14.9%	12,929	7.9%	163,707	774	37,283	22.8%	1,009	235
S_SP2	$80	23,384	15.2%	11,006	7.1%	154,162	795	34,390	22.3%	1,011	216
S_P	$55	18,813	15.3%	9,153	7.5%	122,719	902	27,966	22.8%	1,130	228
S_OP	$25	16,950	22.3%	3,189	4.2%	76,038	1,447	20,139	26.5%	1,634	187
W_SP	$80	24,013	15.4%	11,053	7.1%	156,250	804	35,067	22.4%	1,021	217
W_P	$55	19,150	15.3%	8,973	7.2%	124,828	909	28,123	22.5%	1,130	221
W_OP	$30	18,373	17.8%	4,946	4.8%	102,979	1,102	23,319	22.6%	1,274	172
SH_SP	$65	19,460	16.4%	7,672	6.5%	118,586	850	27,133	22.9%	1,063	213
SH_P	$45	15,842	16.5%	5,462	5.7%	95,869	932	21,304	22.2%	1,120	188
SH_OP	$20	12,975	21.8%	2,440	4.1%	59,411	1,428	15,415	26.0%	1,608	180

Available Economic Capacity

PJM East

PECO and PSE&G Load Only

		Pre-Merger						Post-Merger				Effect of Mitigation		
		Exelon		PSEG				EEG						
Period	Price	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	MW	Mkt Share	HHI	HHI Change	Mitig Share	New HHI Chg	Divest
S_SP1	$250	1,864	5.8%	8,332	25.8%	32,294	1,161	10,196	31.6%	1,459	298	16.5%	(314)	4,877
S_SP2	$80	1,588	5.7%	6,672	23.9%	27,916	1,068	8,261	29.6%	1,340	272	15.5%	(265)	3,947
S_P	$55	1,044	5.3%	5,189	26.4%	19,670	1,136	6,233	31.7%	1,416	280	11.6%	(388)	3,947
S_OP	$25	1,221	9.9%	1,838	15.0%	12,279	856	3,059	24.9%	1,154	298	7.0%	(113)	2,201
W_SP	$80	2,177	8.0%	5,650	20.7%	27,304	967	7,826	28.7%	1,297	330	13.8%	(191)	4,061
W_P	$55	1,827	9.6%	3,818	20.0%	19,068	928	5,645	29.6%	1,311	384	8.3%	(197)	4,061
W_OP	$30	2,403	15.4%	2,113	13.6%	15,585	876	4,515	29.0%	1,294	418	10.8%	(140)	2,833
SH_SP	$65	600	3.3%	3,293	17.9%	18,417	909	3,893	21.1%	1,026	117	3.1%	(158)	3,325
SH_P	$45	898	6.9%	1,242	9.5%	13,083	804	2,140	16.4%	934	130	-1.1%	-	2,289
SH_OP	$20	730	7.2%	445	4.4%	10,095	795	1,175	11.6%	859	64	-6.9%	-	1,872

		Pre-Merger						Post-Merger	
		Load Met by Generation in East		Load Met by Generation in Central		Load Met by Generation in Far West		Total PJM Load	
Period	Price	Exelon	PSEG	Exelon	PSEG	Exelon	PSEG	Exelon	PSEG
S_SP1	$250	4,566	1,180	2,791	1,020	676	-	8,033	2,200
S_SP2	$80	3,942	929	2,791	1,020	336	-	7,069	1,949
S_P	$55	3,758	583	1,798	1,020	-	-	5,556	1,603
S_OP	$25	3,309	331	1,045	1,020	-	-	4,354	1,351
W_SP	$80	4,072	1,958	1,194	1,026	-	150	5,266	3,135
W_P	$55	3,449	1,764	1,051	1,026	-	-	4,501	2,790
W_OP	$30	2,558	1,255	1,051	1,026	-	-	3,609	2,282
SH_SP	$65	3,933	1,609	1,597	831	262	110	5,793	2,550
SH_P	$45	3,403	1,502	1,496	831	142	-	5,041	2,333
SH_OP	$20	3,046	1,164	1,265	831	-	-	4,311	1,995

Note: For purposes of this analysis, mitigation is assumed to be split between two parties that do not have a material market share.

Available Economic Capacity

PJM Pre-2004

PECO and PSE&G Load Only

		Pre-Merger						Post-Merger				Effect of Mitigation		
		Exelon		PSEG				EEG						
Period	Price	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	MW	Mkt Share	HHI	HHI Change	Mitig Share	New HHI Chg	Divest
S_SP1	$250	2,475	3.7%	9,010	13.4%	67,040	860	11,485	17.1%	959	99	9.9%	(71)	4,877
S_SP2	$80	2,476	4.1%	7,340	12.2%	60,363	847	9,816	16.3%	947	100	9.7%	(49)	3,947
S_P	$55	2,420	5.1%	5,852	12.4%	47,358	934	8,272	17.5%	1,061	126	9.1%	(61)	3,947
S_OP	$25	2,062	10.8%	1,838	9.7%	19,044	850	3,900	20.5%	1,059	209	8.9%	(64)	2,201
W_SP	$80	4,633	7.5%	6,200	10.0%	61,838	812	10,833	17.5%	962	150	11.0%	(15)	4,061
W_P	$55	3,798	8.0%	4,483	9.4%	47,641	903	8,280	17.4%	1,053	150	8.9%	(37)	4,061
W_OP	$30	4,092	10.9%	2,665	7.1%	37,666	895	6,757	17.9%	1,048	154	10.4%	(31)	2,833
SH_SP	$65	2,074	4.9%	3,713	8.8%	42,159	897	5,786	13.7%	984	87	5.8%	(37)	3,325
SH_P	$45	1,895	5.8%	1,736	5.3%	32,877	968	3,632	11.1%	1,029	61	4.1%	(20)	2,289
SH_OP	$20	1,161	8.1%	445	3.1%	14,409	838	1,606	11.2%	888	50	-1.8%	-	1,872

		Pre-Merger	
		PJM Load	
Period	Price	Exelon	PSEG
S_SP1	$250	8,033	2,200
S_SP2	$80	7,069	1,949
S_P	$55	5,556	1,603
S_OP	$25	4,354	1,351
W_SP	$80	5,266	3,135
W_P	$55	4,501	2,790
W_OP	$30	3,609	2,282
SH_SP	$65	5,793	2,550
SH_P	$45	5,041	2,333
SH_OP	$20	4,311	1,995

Note: For purposes of this analysis, mitigation is assumed to be split between two parties that do not have a material market share.

Available Economic Capacity

PJM Pre-2004

PECO, PSE&G and PJM Pre-2004 Load

		Pre-Merger						Post-Merger				Effect of Mitigation		
		Exelon		PSEG				EEG						
Period	Price	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	MW	Mkt Share	HHI	HHI Change	Mitig Share	New HHI Chg	Divest
S_SP1	$250	2,393	15.3%	9,010	57.8%	15,596	3,672	11,403	73.1%	5,445	1,772	41.8%	(1,332)	4,877
S_SP2	$80	2,394	16.6%	7,340	51.0%	14,407	2,988	9,734	67.6%	4,682	1,694	40.2%	(883)	3,947
S_P	$55	2,338	20.2%	5,852	50.7%	11,552	3,147	8,190	70.9%	5,197	2,050	36.7%	(1,043)	3,947
S_OP	$25	2,010	26.8%	1,838	24.5%	7,511	1,932	3,848	51.2%	3,241	1,310	21.9%	(405)	2,201
W_SP	$80	4,551	16.7%	6,200	22.8%	27,190	1,054	10,751	39.5%	1,817	763	24.6%	(83)	4,061
W_P	$55	3,716	23.0%	4,483	27.8%	16,141	1,535	8,199	50.8%	2,814	1,279	25.6%	(328)	4,061
W_OP	$30	4,040	33.4%	2,665	22.0%	12,115	1,875	6,705	55.3%	3,342	1,467	32.0%	(302)	2,833
SH_SP	$65	1,992	21.8%	3,713	40.6%	9,143	2,343	5,705	62.4%	4,112	1,770	26.0%	(786)	3,325
SH_P	$45	1,813	26.3%	1,736	25.2%	6,905	1,771	3,550	51.4%	3,091	1,321	18.3%	(439)	2,289
SH_OP	$20	1,109	21.0%	445	8.4%	5,275	1,776	1,554	29.5%	2,131	354	-6.0%	-	1,872

		Pre-Merger		
		Total PJM Load		
Period	Price	Exelon	PSEG	Rest of PJM
S_SP1	$250	8,033	2,200	51,444
S_SP2	$80	7,069	1,949	45,956
S_P	$55	5,556	1,603	40,076
S_OP	$25	4,354	1,351	30,957
W_SP	$80	5,266	3,135	34,647
W_P	$55	4,501	2,790	31,500
W_OP	$30	3,609	2,282	25,551
SH_SP	$65	5,793	2,550	41,297
SH_P	$45	5,041	2,333	36,819
SH_OP	$20	4,311	1,995	32,115

Note: For purposes of this analysis, mitigation is assumed to be split between two parties that do not have a material market share.

Available Economic Capacity

Expanded PJM

PECO, PSE&G, ComEd, AEP and DOM Load

		Pre-Merger						Post-Merger				Effect of Mitigation		
		Exelon		PSEG				EEG						
Period	Price	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	MW	Mkt Share	HHI	HHI Change	Mitig Share	New HHI Chg	Divest
S_SP1	$250	1,937	1.6%	10,729	9.1%	117,893	656	12,666	10.7%	686	30	6.6%	(33)	4,877
S_SP2	$80	1,932	1.7%	9,057	8.1%	111,662	640	10,989	9.8%	668	28	6.3%	(23)	3,947
S_P	$55	2,183	2.5%	7,550	8.5%	88,704	647	9,734	11.0%	689	42	6.5%	(26)	3,947
S_OP	$25	4,123	8.3%	1,838	3.7%	49,524	885	5,961	12.0%	947	62	7.6%	(16)	2,201
W_SP	$80	7,544	6.2%	7,918	6.6%	120,880	615	15,463	12.8%	697	82	9.4%	13	4,061
W_P	$55	5,463	5.8%	6,184	6.6%	94,274	655	11,647	12.4%	731	76	8.0%	(3)	4,061
W_OP	$30	7,420	9.5%	2,665	3.4%	77,931	786	10,085	12.9%	851	65	9.3%	(9)	2,833
SH_SP	$65	2,281	2.8%	5,122	6.4%	80,611	698	7,403	9.2%	734	36	5.1%	(14)	3,325
SH_P	$45	1,397	2.2%	3,128	5.0%	62,601	649	4,525	7.2%	672	22	3.6%	(11)	2,289
SH_OP	$20	590	2.0%	445	1.5%	30,293	919	1,035	3.4%	925	6	-2.8%	-	1,872

		Pre-Merger				Post-Merger		
		Total PJM Load		Supplied by PJM East Generation		Other Load		
Period	Price	Exelon	PSEG	Exelon	PSEG	COMED	AEP	DOM
S_SP1	$250	8,033	2,200	4,566	1,180	18,342	21,198	18,000
S_SP2	$80	7,069	1,949	3,942	929	15,359	19,098	16,217
S_P	$55	5,556	1,603	3,758	583	11,074	15,782	13,402
S_OP	$25	4,354	1,351	3,309	331	8,473	12,336	10,476
W_SP	$80	5,266	3,135	4,072	1,958	11,204	15,766	13,388
W_P	$55	4,501	2,790	3,449	1,764	9,186	14,079	11,955
W_OP	$30	3,609	2,282	2,558	1,255	7,344	11,814	10,032
SH_SP	$65	5,793	2,550	3,933	1,609	11,387	18,245	15,493
SH_P	$45	5,041	2,333	3,403	1,502	10,071	16,489	14,002
SH_OP	$20	4,311	1,995	3,046	1,164	8,365	14,738	12,515

Note: For purposes of this analysis, mitigation is assumed to be split between two parties that do not have a material market share.

Exhibit J-9

PJM Capacity Market

	ICAP: PJM East			ICAP: Expanded PJM		
	MW	Market Share	HHI	MW	Market Share	HHI
Exelon	7,180	18.0%	324	26,465	15.2%	230
PSEG	10,134	25.4%	645	14,137	8.1%	66
AEP	-	0.0%	-	23,980	13.7%	189
Allegheny Energy	-	0.0%	-	9,724	5.6%	31
Conectiv	4,800	12.0%	145	5,717	3.3%	11
Constellation Energy	152	0.4%	0	7,279	4.2%	17
DPL, Inc.	-	0.0%	-	4,799	2.7%	8
Dominion	-	0.0%	-	21,700	12.4%	154
Duke Energy	-	0.0%	-	2,736	1.6%	2
Edison Mission Energy	-	0.0%	-	8,298	4.8%	23
FirstEnergy	1,117	2.8%	8	3,732	2.1%	5
Mirant	-	0.0%	-	6,051	3.5%	12
NRG Energy	1,060	2.7%	7	2,834	1.6%	3
PPL	2,071	5.2%	27	8,911	5.1%	26
Reliant Energy	2,226	5.6%	31	6,805	3.9%	15
Imports	7,300	18.3%	84	7,500	4.3%	5
Others	3,862	9.7%	12	13,984	8.0%	4
Total	39,902	100.0%	1,282	174,650	100.0%	799
Post-Transaction HHI			**2,196**			**1,044**
HHI Change			**914**			**245**
Implied Mitigation Required	**5,300**	13.3%		**2,300**	1.3%	
Adjusted HHI Change			98			198
Adjusted Post-Transaction HHI			1,380			997
Proposed Divestiture	**2,900**			**2,900**		
Remaining Potential Mitigation	**2,400**			**-**		

Note: In calculating HHIs, imports are assumed to be supplied by four equal-sized parties. In calculating implied mitigation, divestiture is assumed to be to two parties whose share of installed capacity in PJM East and Expanded PJM is no more than 5 percent.

Exhibit J-10

PJM Spinning Reserve Market (Mid-Atlantic)

	(MW)	Share
Market Capability	3,033	
Exelon	196	6%
PSEG	1,191	39%
Other	1,646	54%
Market Concentration		Moderate
HHI Change		507
Implied Divestiture		147
HHI Change		99

Note: In calculating implied divestiture, sales are assumed to be to two parties whose share of nstalled capacity in PJM East and Expanded PJM is no more than 5 percent.

Exhibit J-11

PJM Regulation Market (Mid-Atlantic)

	(MW)	Share
Market Capability	2,011	
Exelon	267	13%
PSEG	241	12%
Other	1,504	75%

Exhibit J-12

Mitigation-Eligible Units

Unit	Type	Summer MW	Winter MW	Summer Economic < $25	Summer Economic Between $25 and $55/MWh	Summer Economic Between $55 and $80/MWh	Summer Economic Between $80 and $250/MWh
Grand Central Landfill	NUG	9	9	x			
Pottstown Landfill	NUG	10	10	x			
MMLP NUG (Montenay)	NUG	28	28	x			
Conowingo	HY	512	512	x			
Oyster Creek	NU	619	637	x			
Limerick	NU	2,268	2,358	x			
Salem	NU	2,221	2,066	x			
Hope Creek	NU	1,049	1,118	x			
Yards Creek	HY	200	200		x		
Eddystone 1-2	ST	579	599		x		
Cromby 1	ST	144	147		x		
Hudson 2	ST	608	620		x		
Mercer 1-2	ST	648	682		x		
Bergen, 1ST, 1SC, 1CC	CC	1,225	1,245		x		
Linden CC	CC	1,218	1,218		x		
Bergen 3	GT	21	24			x	
Sewaren 1-4	ST	453	495			x	
Hudson 1	ST	383	422			x	
Kearny 7-8	ST	300	340			x	
Pennsbury 1-2	GT	6	6			x	
Cromby 2	ST	201	211			x	
Kearny (PSEG)	CT	134	159			x	
Burlington (PSEG)	CT	168	200			x	
Eddystone 3-4	ST	760	760			x	
Essex	GT	81	93			x	
Linden 7-8	GT	156	186			x	
Edison	GT	168	194			x	
Fairless Hills	ST	60	60				x
Cromby IC1	IC1	3	3				x
Delaware 1	1	3	3				x
Schuylkill 1, 10-11, IC1	ST, GT IC1	199	216				x
Croydon	GT	384	497				x
Essex 10, 11, 12	GT	536	618				x
Edison	GT	336	388				x
Richmond	GT	96	132				x
Kearny 9, 10, 12	GT	330	383				x
National Park	GT	21	24				x
Falls	GT	51	60				x
Moser	GT	51	60				x
Delaware 9-12	GT	56	74				x
Eddystone 10-40	GT	60	76				x
Southwark 3-6	GT	52	72				x
Chester 7-9	GT	39	54				x
Burlington 8-11	GT	389	448				x
Bayonne 1-2	GT	42	48				x
Sewaren 6	GT	129	140				x
Mercer 3	GT	129	140				x
Linden 5,6	GT	160	188				x
Salem 3	GT	38	46				x
Total		17,332	18,268	6,715	4,622	2,831	3,164

Note: Units are economic within 105% of market price.

Mitigation-Eligible Units

Unit	Type	Summer MW	Winter MW	Winter: Economic < $30	Winter: Economic Between $30 and $55/MWh	Winter: Economic Between $55 and $80/MWh
Grand Central Landfill	NUG	9	9	x		
Pottstown Landfill	NUG	10	10	x		
MMLP NUG (Montenay)	NUG	28	28	x		
Conowingo	HY	512	512	x		
Oyster Creek	NU	619	637	x		
Limerick	NU	2,268	2,358	x		
Salem	NU	2,221	2,066	x		
Hope Creek	NU	1,049	1,118	x		
Yards Creek	HY	200	200	x		
Eddystone 1-2	ST	579	599	x		
Cromby 1	ST	144	147	x		
Hudson 2	ST	608	620	x		
Mercer 1-2	ST	648	682	x		
Bergen, 1ST, 1SC, 1CC	CC	1,225	1,245		x	
Linden CC	CC	1,218	1,218		x	
Bergen 3	GT	21	24			x
Sewaren 1-4	ST	453	495			x
Hudson 1	ST	383	422			x
Kearny 7-8	ST	300	340			x
Pennsbury 1-2	GT	6	6			x
Cromby 2	ST	201	211			x
Kearny (PSEG)	CT	134	159			x
Burlington (PSEG)	CT	168	200			x
Eddystone 3-4	ST	760	760			x
Essex	GT	81	93			x
Linden 7-8	GT	156	186			x
Edison	GT	168	194			x
Fairless Hills	ST	60	60			x
Cromby IC1	IC1	3	3			
Delaware 1	1	3	3			
Schuylkill 1, 10-11, IC1	ST, GT IC1	199	216			
Croydon	GT	384	497			
Essex 10, 11, 12	GT	536	618			
Edison	GT	336	388			
Richmond	GT	96	132			
Kearny 9, 10, 12	GT	330	383			
National Park	GT	21	24			
Falls	GT	51	60			
Moser	GT	51	60			
Delaware 9-12	GT	56	74			
Eddystone 10-40	GT	60	76			
Southwark 3-6	GT	52	72			
Chester 7-9	GT	39	54			
Burlington 8-11	GT	389	448			
Bayonne 1-2	GT	42	48			
Sewaren 6	GT	129	140			
Mercer 3	GT	129	140			
Linden 5,6	GT	160	188			
Salem 3	GT	38	46			
Total		17,332	18,268	8,985	2,463	3,150

Note: Units are economic within 105% of market price.

Mitigation-Eligible Units

Unit	Type	Summer MW	Winter MW	Shoulder: Economic < $20	Shoulder: Economic Between $20 and $45/MWh	Shoulder: Economic Between $45 and $65/MWh
Grand Central Landfill	NUG	9	9	x		
Pottstown Landfill	NUG	10	10	x		
MMLP NUG (Montenay)	NUG	28	28	x		
Conowingo	HY	512	512	x		
Oyster Creek	NU	619	637	x		
Limerick	NU	2,268	2,358	x		
Salem	NU	2,221	2,066	x		
Hope Creek	NU	1,049	1,118	x		
Yards Creek	HY	200	200		x	
Eddystone 1-2	ST	579	599		x	
Cromby 1	ST	144	147		x	
Hudson 2	ST	608	620		x	
Mercer 1-2	ST	648	682		x	
Bergen, 1ST, 1SC, 1CC	CC	1,225	1,245			x
Linden CC	CC	1,218	1,218			x
Bergen 3	GT	21	24			
Sewaren 1-4	ST	453	495			
Hudson 1	ST	383	422			
Kearny 7-8	ST	300	340			x
Pennsbury 1-2	GT	6	6			x
Cromby 2	ST	201	211			
Kearny (PSEG)	CT	134	159			
Burlington (PSEG)	CT	168	200			
Eddystone 3-4	ST	760	760			
Essex	GT	81	93			
Linden 7-8	GT	156	186			
Edison	GT	168	194			
Fairless Hills	ST	60	60			
Cromby IC1	IC1	3	3			
Delaware 1	1	3	3			
Schuylkill 1, 10-11, IC1	ST, GT IC1	199	216			
Croydon	GT	384	497			
Essex 10, 11, 12	GT	536	618			
Edison	GT	336	388			
Richmond	GT	96	132			
Kearny 9, 10, 12	GT	330	383			
National Park	GT	21	24			
Falls	GT	51	60			
Moser	GT	51	60			
Delaware 9-12	GT	56	74			
Eddystone 10-40	GT	60	76			
Southwark 3-6	GT	52	72			
Chester 7-9	GT	39	54			
Burlington 8-11	GT	389	448			
Bayonne 1-2	GT	42	48			
Sewaren 6	GT	129	140			
Mercer 3	GT	129	140			
Linden 5,6	GT	160	188			
Salem 3	GT	38	46			
Total		17,332	18,268	6,715	2,179	2,749

Note: Units are economic within 105% of market price.

Mitigation Scenarios

Scenario 1: Mitigation Required for PJM East

	Summer MW	Winter MW	Outages			Derated Capacity			Dispatch Cost (+5%)		
			Summer	Winter	Shoulder	Summer	Winter	Shoulder	Summer	Winter	Shoulder
Nuclear	**2,400**	2,496	92%	92%	75%	2,201	2,289	1,800	<$15	<$15	<$15
Coal	**550**	579	94%	94%	72%	517	544	396	<$55	<$30	<$30
Mid-Merit	**1,350**	1,350	91%	91%	77%	1,229	1,229	1,037	<$80	<$80	<$80
Peaking	**1,000**	1,155	93%	93%	75%	931	1,072	750	>$80	>$80	>$80
Total	**5,300**										

Adjusted for Nuclear Virtual Divestiture based on Exelon 3-yr average Capacity Factor = 93.2%

Nuclear	**2,237**
Coal	**550**
Mid-Merit	**1,350**
Peaking	**1,000**
Total	**5,137**

Note: The coal and mid-merit mitigation amounts are partially interchangeable, so long as the total remains the same. Of the Mid-Merit, 1,200 MW must be economic at the $55/MWh price.

Mitigation Scenarios

Scenario 2: Total Mitigation (Additional Mitigation Outside of PJM East)

	Summer MW	Winter MW	Outages			Derated Capacity			Dispatch Cost (+5%)		
			Summer	Winter	Shoulder	Summer	Winter	Shoulder	Summer	Winter	Shoulder
Nuclear	**2,600**	2,704	92%	92%	75%	2,385	2,480	1,950	<$15	<$15	<$15
Coal	**550**	579	94%	94%	72%	517	544	396	<$55	<$30	<$30
Mid-Merit	**1,350**	1,350	91%	91%	77%	1,229	1,229	1,037	<$80	<$80	<$80
Peaking	**1,000**	1,155	93%	93%	75%	931	1,072	750	>$80	>$80	>$80
	5,500										

Adjusted for Nuclear Virtual Divestiture based on Exelon 3-yr average Capacity Factor = 93.2%

Nuclear	***2,423***
Coal	**550**
Mid-Merit	**1,350**
Peaking	**1,000**
Total	**5,323**

Note: The coal and mid-merit mitigation amounts are partially interchangeable, so long as the total remains the same. Of the Mid-Merit, 1,200 MW must be economic at the $55/MWh price.

Exhibit J-14

Economic Capacity (Post-Mitigation Results)

		Pre-Merger						Post-Merger				Mitigation and Post-Mitigation Results					
		Exelon		PSEG				EEG									
Period	Price	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	MW	Mkt Share	HHI	HHI Chg	Mitigation MW	Nuclear	Mkt Share	HHI	HHI Chg	MW Summer Equivalent
Scenario 1: Mitigation Required for PJM East																	
PJM East																	
S_SP1	$250	6,961	18.3%	9,658	25.4%	38,040	1,298	16,620	43.7%	2,227	929	4,877	2,201	30.9%	1,329	31	5,300
S_SP2	$80	6,032	18.4%	7,757	23.7%	32,786	1,218	13,788	42.1%	2,088	870	3,947	2,201	30.0%	1,273	55	4,300
S_P	$55	5,122	21.3%	5,957	24.8%	24,011	1,327	11,079	46.1%	2,385	1,058	3,947	2,201	29.7%	1,236	(91)	4,300
S_OP	$25	4,887	30.7%	2,631	16.5%	15,919	1,477	7,518	47.2%	2,492	1,015	2,201	2,201	33.4%	1,473	(4)	2,400
W_SP	$80	6,417	19.3%	7,796	23.4%	33,333	1,228	14,213	42.6%	2,128	900	4,061	2,289	30.5%	1,291	63	4,300
W_P	$55	5,451	22.5%	5,770	23.8%	24,281	1,323	11,221	46.2%	2,390	1,067	4,061	2,289	29.5%	1,222	(101)	4,300
W_OP	$30	5,167	26.6%	3,594	18.5%	19,398	1,324	8,761	45.2%	2,311	987	2,833	2,289	30.6%	1,297	(27)	2,950
SH_SP	$65	4,896	20.4%	5,095	21.3%	23,958	1,187	9,991	41.7%	2,057	870	3,233	1,800	28.2%	1,181	(6)	4,300
SH_P	$45	4,675	26.0%	2,935	16.3%	17,988	1,257	7,610	42.3%	2,105	848	2,196	1,800	30.1%	1,287	30	2,950
SH_OP	$20	4,338	30.3%	2,051	14.3%	14,305	1,406	6,389	44.7%	2,276	870	1,800	1,800	32.1%	1,389	(17)	2,400
PJM Pre-2004																	
S_SP1	$250	10,508	13.6%	11,210	14.5%	77,273	896	21,718	28.1%	1,291	395	4,877	2,201	21.8%	1,011	115	5,300
S_SP2	$80	9,545	13.8%	9,288	13.4%	69,380	885	18,834	27.2%	1,254	369	3,947	2,201	21.5%	1,005	120	4,300
S_P	$55	7,976	14.6%	7,455	13.7%	54,517	971	15,431	28.3%	1,371	400	3,947	2,201	21.1%	1,056	85	4,300
S_OP	$25	6,416	25.9%	3,189	12.9%	24,749	1,217	9,605	38.8%	1,885	668	2,201	2,201	29.9%	1,314	97	2,400
W_SP	$80	9,899	14.1%	9,334	13.3%	70,238	883	19,233	27.4%	1,257	374	4,061	2,289	21.6%	1,003	120	4,300
W_P	$55	8,299	15.1%	7,273	13.2%	54,932	968	15,571	28.4%	1,368	400	4,061	2,289	21.0%	1,047	79	4,300
W_OP	$30	7,701	17.7%	4,946	11.4%	43,557	985	12,648	29.0%	1,386	401	2,833	2,289	22.5%	1,080	95	2,950
SH_SP	$65	7,866	15.6%	6,263	12.4%	50,501	951	14,129	28.0%	1,337	386	3,233	1,800	21.6%	1,054	103	4,300
SH_P	$45	6,936	17.2%	4,070	10.1%	40,251	1,004	11,006	27.3%	1,353	349	2,196	1,800	21.9%	1,105	101	2,950
SH_OP	$20	5,472	26.4%	2,440	11.8%	20,715	1,206	7,912	38.2%	1,828	622	1,800	1,800	29.5%	1,278	72	2,400

Economic Capacity (Post-Mitigation Results)

		Pre-Merger						Post-Merger				Mitigation and Post-Mitigation Results					
		Exelon		PSEG				EEG									
Period	Price	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	MW	Mkt Share	HHI	HHI Chg	Mitigation MW	Nuclear	Mkt Share	HHI	HHI Chg	MW Summer Equivalent
Scenario 1: Mitigation Required for PJM East																	
PJM Expanded																	
S_SP1	$250	24,354	14.9%	12,929	7.9%	163,707	774	37,283	22.8%	1,009	235	4,877	2,201	19.8%	896	122	5,300
S_SP2	$80	23,384	15.2%	11,006	7.1%	154,162	795	34,390	22.3%	1,011	216	3,947	2,201	19.7%	914	119	4,300
S_P	$55	18,813	15.3%	9,153	7.5%	122,719	902	27,966	22.8%	1,130	228	3,947	2,201	19.6%	1,009	107	4,300
S_OP	$25	16,950	22.3%	3,189	4.2%	76,038	1,447	20,139	26.5%	1,634	187	2,201	2,201	23.6%	1,493	46	2,400
W_SP	$80	24,013	15.4%	11,053	7.1%	156,250	804	35,067	22.4%	1,021	217	4,061	2,289	19.8%	922	118	4,300
W_P	$55	19,150	15.3%	8,973	7.2%	124,828	909	28,123	22.5%	1,130	221	4,061	2,289	19.3%	1,008	99	4,300
W_OP	$30	18,373	17.8%	4,946	4.8%	102,979	1,102	23,319	22.6%	1,274	172	2,833	2,289	19.9%	1,165	63	2,950
SH_SP	$65	19,460	16.4%	7,672	6.5%	118,586	850	27,133	22.9%	1,063	213	3,233	1,800	20.2%	956	106	4,300
SH_P	$45	15,842	16.5%	5,462	5.7%	95,869	932	21,304	22.2%	1,120	188	2,196	1,800	19.9%	1,029	97	2,950
SH_OP	$20	12,975	21.8%	2,440	4.1%	59,411	1,428	15,415	26.0%	1,608	180	1,800	1,800	22.9%	1,464	36	2,400

Economic Capacity (Post-Mitigation Results)

		Pre-Merger						Post-Merger				Mitigation and Post-Mitigation Results					
		Exelon		PSEG				EEG									
Period	Price	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	MW	Mkt Share	HHI	HHI Chg	Mitigation MW	Nuclear	Mkt Share	HHI	HHI Chg	MW Summer Equivalent
Scenario 2: Total Mitigation (Additional Mitigation Outside of PJM East)																	
PJM Pre-2004																	
S_SP1	$250	10,508	13.6%	11,210	14.5%	77,273	896	21,718	28.1%	1,291	395	5,061	2,385	21.6%	1,002	106	5,500
S_SP2	$80	9,545	13.8%	9,288	13.4%	69,380	885	18,834	27.2%	1,254	369	4,130	2,385	21.2%	995	110	4,500
S_P	$55	7,976	14.6%	7,455	13.7%	54,517	971	15,431	28.3%	1,371	400	4,130	2,385	20.7%	1,043	72	4,500
S_OP	$25	6,416	25.9%	3,189	12.9%	24,749	1,217	9,605	38.8%	1,885	668	2,385	2,385	29.2%	1,277	60	2,600
W_SP	$80	9,899	14.1%	9,334	13.3%	70,238	883	19,233	27.4%	1,257	374	4,252	2,480	21.3%	993	110	4,500
W_P	$55	8,299	15.1%	7,273	13.2%	54,932	968	15,571	28.4%	1,368	400	4,252	2,480	20.6%	1,034	66	4,500
W_OP	$30	7,701	17.7%	4,946	11.4%	43,557	985	12,648	29.0%	1,386	401	3,024	2,480	22.1%	1,063	78	3,150
SH_SP	$65	7,866	15.6%	6,263	12.4%	50,501	951	14,129	28.0%	1,337	386	3,383	1,950	21.3%	1,043	92	4,500
SH_P	$45	6,936	17.2%	4,070	10.1%	40,251	1,004	11,006	27.3%	1,353	349	2,346	1,950	21.5%	1,090	86	3,150
SH_OP	$20	5,472	26.4%	2,440	11.8%	20,715	1,206	7,912	38.2%	1,828	622	1,950	1,950	28.8%	1,242	36	2,600
PJM Expanded																	
S_SP1	$250	24,354	14.9%	12,929	7.9%	163,707	774	37,283	22.8%	1,009	235	5,061	2,385	19.7%	892	118	5,500
S_SP2	$80	23,384	15.2%	11,006	7.1%	154,162	795	34,390	22.3%	1,011	216	4,130	2,385	19.6%	910	115	4,500
S_P	$55	18,813	15.3%	9,153	7.5%	122,719	902	27,966	22.8%	1,130	228	4,130	2,385	19.4%	1,004	102	4,500
S_OP	$25	16,950	22.3%	3,189	4.2%	76,038	1,447	20,139	26.5%	1,634	187	2,385	2,385	23.3%	1,483	36	2,600
W_SP	$80	24,013	15.4%	11,053	7.1%	156,250	804	35,067	22.4%	1,021	217	4,252	2,480	19.7%	917	113	4,500
W_P	$55	19,150	15.3%	8,973	7.2%	124,828	909	28,123	22.5%	1,130	221	4,252	2,480	19.1%	1,003	94	4,500
W_OP	$30	18,373	17.8%	4,946	4.8%	102,979	1,102	23,319	22.6%	1,274	172	3,024	2,480	19.7%	1,158	56	3,150
SH_SP	$65	19,460	16.4%	7,672	6.5%	118,586	850	27,133	22.9%	1,063	213	3,383	1,950	20.0%	951	101	4,500
SH_P	$45	15,842	16.5%	5,462	5.7%	95,869	932	21,304	22.2%	1,120	188	2,346	1,950	19.8%	1,023	91	3,150
SH_OP	$20	12,975	21.8%	2,440	4.1%	59,411	1,428	15,415	26.0%	1,608	180	1,950	1,950	22.7%	1,453	25	2,600

Downstream Results, Economic Capacity

Period	Price	Post-Merger: EEG MW	Post-Merger: Mkt Share	Post-Merger: Mkt Size	Post-Merger: HHI	Post-Merger: HHI Chg	Mitigation and Post-Mitigation Results: Mitigation MW	Nuclear	Mkt Share	HHI	HHI Chg	MW Summer Equivalent
Scenario 1: Mitigation Required for PJM East												
PJM East												
S_SP1	$250	18,636	49.0%	38,040	2,622		2,718	2,201	41.8%	1,999	(623)	2,950
S_SP2	$80	15,804	48.2%	32,786	2,540		2,718	2,201	39.9%	1,845	(695)	2,950
S_P	$55	11,818	49.2%	24,011	2,649		2,718	2,201	37.9%	1,728	(921)	2,950
S_OP	$25	8,257	51.9%	15,919	2,920		2,201	2,201	38.0%	1,772	(1,148)	2,400
W_SP	$80	16,301	48.9%	33,333	2,607		2,833	2,289	40.4%	1,885	(722)	2,950
W_P	$55	12,029	49.5%	24,281	2,678		2,833	2,289	37.9%	1,727	(951)	2,950
W_OP	$30	9,570	49.3%	19,398	2,668		2,833	2,289	34.7%	1,553	(1,115)	2,950
SH_SP	$65	11,134	46.5%	23,958	2,404		2,196	1,800	37.3%	1,680	(724)	2,950
SH_P	$45	8,235	45.8%	17,988	2,376		2,196	1,800	33.6%	1,488	(888)	2,950
SH_OP	$20	7,014	49.0%	14,305	2,652		1,800	1,800	36.4%	1,656	(996)	2,400
PJM Pre-2004												
S_SP1	$250	23,734	30.7%	77,273	1,371		2,718	2,201	27.2%	1,183	(188)	2,950
S_SP2	$80	20,850	30.1%	69,380	1,352		2,718	2,201	26.1%	1,150	(202)	2,950
S_P	$55	16,170	29.7%	54,517	1,439		2,718	2,201	24.7%	1,194	(245)	2,950
S_OP	$25	10,344	41.8%	24,749	2,105		2,201	2,201	32.9%	1,480	(625)	2,400
W_SP	$80	21,321	30.4%	70,238	1,362		2,833	2,289	26.3%	1,152	(210)	2,950
W_P	$55	16,380	29.8%	54,932	1,443		2,833	2,289	24.7%	1,189	(254)	2,950
W_OP	$30	13,456	30.9%	43,557	1,483		2,833	2,289	24.4%	1,166	(317)	2,950
SH_SP	$65	15,272	30.2%	50,501	1,415		2,196	1,800	25.9%	1,190	(225)	2,950
SH_P	$45	11,631	28.9%	40,251	1,426		2,196	1,800	23.4%	1,170	(256)	2,950
SH_OP	$20	8,537	41.2%	20,715	2,046		1,800	1,800	32.5%	1,443	(603)	2,400

Downstream Results, Economic Capacity

Period	Price	Post-Merger: EEG MW	Post-Merger: Mkt Share	Post-Merger: Mkt Size	Post-Merger: HHI	Post-Merger: HHI Chg	Mitigation and Post-Mitigation Results: Mitigation MW	Nuclear	Mkt Share	HHI	HHI Chg	MW Summer Equivalent
Scenario 1: Mitigation Required for PJM East												
PJM Expanded												
S_SP1	$250	39,299	24.0%	163,707	1,043		2,718	2,201	22.3%	970	(73)	2,950
S_SP2	$80	36,407	23.6%	154,162	1,050		2,718	2,201	21.9%	974	(76)	2,950
S_P	$55	28,706	23.4%	122,719	1,155		2,718	2,201	21.2%	1,061	(94)	2,950
S_OP	$25	20,879	27.5%	76,038	1,685		2,201	2,201	24.6%	1,539	(146)	2,400
W_SP	$80	37,155	23.8%	156,250	1,063		2,833	2,289	22.0%	984	(79)	2,950
W_P	$55	28,932	23.2%	124,828	1,156		2,833	2,289	20.9%	1,061	(95)	2,950
W_OP	$30	24,128	23.4%	102,979	1,307		2,833	2,289	20.7%	1,193	(114)	2,950
SH_SP	$65	28,276	23.8%	118,586	1,089		2,196	1,800	22.0%	1,008	(81)	2,950
SH_P	$45	21,929	22.9%	95,869	1,145		2,196	1,800	20.6%	1,051	(94)	2,950
SH_OP	$20	16,040	27.0%	59,411	1,661		1,800	1,800	24.0%	1,511	(150)	2,400

Downstream Results, Economic Capacity

Period	Price	EEG MW	Mkt Share	Mkt Size	HHI	HHI Chg	Mitigation MW	Nuclear	Mkt Share	HHI	HHI Chg	MW Summer Equivalent
		Post-Merger					Mitigation and Post-Mitigation Results					
Scenario 2: Total Mitigation (Additional Mitigation Outside of PJM East)												
PJM Pre-2004												
S_SP1	$250	23,734	30.7%	77,273	1,371		2,901	2,385	27.0%	1,171	(200)	3,150
S_SP2	$80	20,850	30.1%	69,380	1,352		2,901	2,385	25.9%	1,137	(215)	3,150
S_P	$55	16,170	29.7%	54,517	1,439		2,901	2,385	24.3%	1,179	(260)	3,150
S_OP	$25	10,344	41.8%	24,749	2,105		2,385	2,385	32.2%	1,439	(666)	2,600
W_SP	$80	21,321	30.4%	70,238	1,362		3,024	2,480	26.1%	1,139	(223)	3,150
W_P	$55	16,380	29.8%	54,932	1,443		3,024	2,480	24.3%	1,174	(269)	3,150
W_OP	$30	13,456	30.9%	43,557	1,483		3,024	2,480	24.0%	1,147	(336)	3,150
SH_SP	$65	15,272	30.2%	50,501	1,415		2,346	1,950	25.6%	1,176	(239)	3,150
SH_P	$45	11,631	28.9%	40,251	1,426		2,346	1,950	23.1%	1,155	(271)	3,150
SH_OP	$20	8,537	41.2%	20,715	2,046		1,950	1,950	31.8%	1,403	(643)	2,600
PJM Expanded												
S_SP1	$250	39,299	24.0%	163,707	1,043		2,901	2,385	22.2%	965	(78)	3,150
S_SP2	$80	36,407	23.6%	154,162	1,050		2,901	2,385	21.7%	969	(81)	3,150
S_P	$55	28,706	23.4%	122,719	1,155		2,901	2,385	21.0%	1,055	(100)	3,150
S_OP	$25	20,879	27.5%	76,038	1,685		2,385	2,385	24.3%	1,528	(157)	2,600
W_SP	$80	37,155	23.8%	156,250	1,063		3,024	2,480	21.8%	979	(84)	3,150
W_P	$55	28,932	23.2%	124,828	1,156		3,024	2,480	20.8%	1,055	(101)	3,150
W_OP	$30	24,128	23.4%	102,979	1,307		3,024	2,480	20.5%	1,186	(121)	3,150
SH_SP	$65	28,276	23.8%	118,586	1,089		2,346	1,950	21.9%	1,003	(86)	3,150
SH_P	$45	21,929	22.9%	95,869	1,145		2,346	1,950	20.4%	1,045	(100)	3,150
SH_OP	$20	16,040	27.0%	59,411	1,661		1,950	1,950	23.7%	1,500	(161)	2,600

Pipelines Flowing into PJM East

Pipeline Name	Delivering From State	Delivering To State	2003 Capacity MMcf/D
Columbia Gas Transmission	PA	NJ	261
Columbia Gas Transmission	PA	DE	174
Tennessee	PA	NJ	499
Texas Eastern	PA	NJ	2,950
Transcontinential	MD	PA	2,050
Total			**5,934**

Source: EIA State Border Capacity (January 2004).

PJM East Delivered Gas Transportation Market

Affiliate Name	Capacity MMcf/D	Market Share	HHI
Exelon/PSEG	2,115	35.6%	1,270
New Jersey Resources	696	11.7%	138
El Paso	322	5.4%	29
Williams Energy	318	5.4%	29
NiSource Inc	259	4.4%	19
Keyspan	252	4.2%	18
NUI Corporation	242	4.1%	17
South Jersey Industries	231	3.9%	15
UGI Corp	141	2.4%	6
Philadelphia Gas Works	136	2.3%	5
Southern Union Company	128	2.2%	5
NSTAR	105	1.8%	3
Others	990	16.7%	19
Total	**5,934**	**100.0%**	**1,572**

Source: Based on data in FERC 549B (January 2005) and EIA State Border Capacity (January 2004).

PECO STATEMENT NO. 3-R
(REVISED)

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

JK
9-22-05
Phila

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	:	DOCKET NO. A-110550F0160

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REBUTTAL TESTIMONY

OF

WILLIAM H. HIERONYMUS

DOCUMENT FOLDER

ADDRESSING MARKET POWER ISSUES

Date: July 29, 2005

REBUTTAL TESTIMONY OF WILLIAM H. HIERONYMUS

I. INTRODUCTION AND SUMMARY

Q. What is the purpose of your rebuttal testimony?

A. I have been asked by Exelon and PSEG to respond to the testimony of interveners concerning issues relevant to competition. I respond in particular to the testimony of Dr. Joseph Kalt on behalf of PPL; Ms. Julia Frayer on behalf of FirstEnergy; Dr. Paul Carpenter on behalf of Philadelphia Gas Works[redacted].

In responding to the intervener testimony, I note that my Supplemental Testimony filed at FERC also has been filed in this docket. Where appropriate, however, I repeat some of the issues addressed therein in order to create a more comprehensive document. I also incorporate by reference my Supplemental Testimony.

Q. Before responding in detail to these testimonies, do you have any general comment?

A. Yes. To an overwhelming degree, the essential point of these testimonies is that this merger fails FERC's screening tests used to determine whether a merger causes competitive harm in wholesale electricity markets. There are no allegations that other effects (e.g. arising from the merger of retail activities, distribution systems or transmission) will cause customers to fail to receive the benefits of competitive electricity markets. Of course, these testimonies were filed prior to FERC's approval of the merger. Indeed, the core of most of them either was filed in the FERC proceeding by these same witnesses, or was in the testimony of other witnesses in the FERC proceeding.

Both here, and in the FERC proceeding, interveners argued that 1) my analysis was flawed and inconsistent with the FERC merger analysis rules, or at least sufficiently questionable that a hearing should be held, and/or 2) that Applicants' mitigation commitments were somehow insufficient. FERC, whose test is at issue, evaluated each of these allegations and rejected them. While I am not a lawyer and have no opinion as to whether FERC's decision is in any way binding on this Commission, it is the case that FERC is the author of the test that these witnesses argue is failed and has extensive experience in applying the test. At a minimum, FERC's decision that the merger, as mitigated, causes no harm to competitive energy markets should be accorded substantial weight.

Another overriding point that I want to make is that, under the DOJ Merger Guidelines and FERC Merger Regulations pursuant to which I conducted my analysis, conducting an HHI screen is only the first step required to find that a proposed merger raises market power concerns. If, as my analysis demonstrated and FERC found, the HHI screens are not violated, then it is appropriate to find that no market power concerns are raised by a transaction. If, on the other hand, as the interveners appear to claim, the HHI screens are violated, then the next step is to evaluate in more detail at hearing whether Applicants in fact would be able to exercise market power. Yet, [redacted] no witness goes beyond their criticisms of my HHI analysis to address whether in fact Applicants could exercise market power after the transaction. [redacted]

Q. Is there anything in the interveners' testimonies that causes you to change your opinions or conclusions?

A. No.

My conclusion is straightforward, notwithstanding challenges to my analysis: the merger as mitigated by Applicants and conditioned and approved by FERC will not harm competition in electricity markets. No additional mitigation is required to satisfy the reasonable standard that the merger not harm competition. The fact that Applicants' divestiture is subject to a compliance filing at FERC ensures that proper consideration is given to the specific assets that are divested and the purchasers that buy them. Any additional divestiture found necessary by interveners (apart from amounts needed to relax buyer restrictions) is due either to misapplication of Applicants' mitigation commitments, misunderstanding of the screens themselves, or market definitions that are not applicable.

I recommend that the Commission find that this transaction does not have a competitive effect on relevant markets and will not impede the ability of Pennsylvania consumers to benefit from competitive electricity markets.

Q. Please summarize the pertinent issues raised in the intervener testimony with respect to competition.

A. There are five primary issues raised by interveners.

Model Assumptions. The analytical/modeling issues raised by interveners include the choice of market prices and fuel cost assumptions (Frayer and Kalt[redacted]), the alleged "knife-edge" results (i.e., results that are sensitive to changes in units' variable costs) (Kalt and Frayer), [redacted], FTRs and the effect on allocation of imports into PJM East (Kalt[redacted]). I have considered each of these issues and demonstrate below why my analysis remains robust.

Market Definition. Dr. Kalt argues that PJM Classic, rather than PJM Pre-2004 is the relevant market to consider when PJM East is not constrained. I disagree, as did FERC, and provide additional evidence supporting my choice of market definitions.

[redacted]

Gas Vertical Issues. Dr. Carpenter argues that I overstated the supply (and, hence understated the concentration) in relevant upstream markets by including volumes that were contracted for deliveries to further upstream markets. However, Dr. Carpenter's logic is flawed and, moreover, if it were evenly applied, would indicate that my conclusion is correct that the relevant market is not highly concentrated.

Mitigation. Several interveners argue for additional mitigation. The assertion that additional mitigation is needed arises from several sources: flaws in the intervener analyses (Kalt and Frayer), different market definitions (Kalt), [redacted] concerns over the efficacy of virtual divestiture (Kalt) [redacted], a desire to allow larger purchasers to acquire large amounts of capacity ([redacted] Kalt[redacted]). Thus, my response to whether additional mitigation is required largely is addressed by rebutting the underlying bases that argue for increased mitigation. Additionally, I discuss why virtual divestiture is an effective means of mitigation.

II. MODEL ASSUMPTIONS

Q. What is the starting point for addressing the analytic and modeling assumptions criticized by interveners?

A. Clearly, the starting point is my Supplemental Testimony filed at FERC and here at the Commission, including the expanded mitigation commitments agreed to by Applicants and accepted by FERC in its Order approving the merger.[1] My original testimony remains relevant as to the foundation of my analysis, but any changes in my analysis and the mitigation proposal incorporated in my Supplemental Testimony necessarily provide the basis for responding to interveners' testimony.

Miscellaneous Errors Alleged by Ms. Frayer

Q. As an initial matter, has Ms. Frayer raised any new criticisms of your analysis in this proceeding?

A. No, she did not. Instead, Ms. Frayer simply attached as exhibits to her testimony in this proceeding copies of her testimony submitted to FERC. Therefore, more than any other witness who has presented market power testimony to this Commission, Ms. Frayer's criticisms all were addressed by FERC in the FERC Merger Order.

Q. Ms. Frayer identifies a number of alleged errors in your model and analysis (setting aside, for the moment, issues about market prices). Are any of these material?

A. No, they are not.

Q. Please describe the criticisms contained in her FERC Direct Testimony.

A. First, she disputes my assumptions about entry and retirements. I responded in my FERC Supplemental Testimony by demonstrating that she misunderstood my assumptions about

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[1] Exelon Corporation and Public Service Enterprise Corporation, Inc., Order Authorizing Merger Under Section 203 Of The Federal Power Act, 112 FERC ¶ 61,011 (2005). ("FERC Merger Order")

entry, and that my analysis was not based on an overstatement of new generation entry as she believed. Ms. Frayer claimed to have "corrected" my analysis by reducing new entry by approximately 1,000 MW, and increasing retirements by 103 MW. However, no reduction in entry was appropriate. The alleged difference of 103 MW with respect to retirements is on its face trivial and, in my supplemental testimony I added 30 MW of retirements to reflect other intervener comments. Moreover, as I pointed out in my Supplemental Testimony, while Ms. Frayer criticized my construction and retirement assumptions at length, she did not in fact change either entry or retirements in her analysis, so the alleged difference cannot account for any difference in results, a fact that I confirmed by examining her workpapers for ICAP and energy markets.

Second, she disputes my fuel cost forecasts. With respect to gas, she rejects my reliance on the U.S. Department of Energy's Energy Information Administration ("EIA") forecasts rather than NYMEX forward market prices. On coal, she simply uses an alternative forecast of her own making. But, her analysis is flawed and does not undermine my analysis in any way. As I will discuss later, the key requirement of the analysis is to reflect a broad range of market conditions, as represented by price levels, and to assure consistency between the prices and the input cost of generators. The former is necessary to assure that there are no time periods in which the merger systematically will injure competition. The latter is necessary to assure that the structure of market supply that is economic ("in the money") is accurately represented for the market condition being modeled. Most importantly, however, while Ms. Frayer claims a modest error in my gas-fired generation costs, she committed a substantial error using materially wrong fuel cost inputs for coal units. Ms. Frayer originally estimated delivered coal costs of $4.93/MMBtu at Big Sandy River (the Central Appalachian Coal price point for NYMEX), which equates to roughly $125 per ton coal prices. Similar prices were used for all coal generation. In contrast, this type of coal is currently trading for about $60/ton on a forward basis for 2006. It appears that what Ms. Frayer did is to assume that the tons-to-MMBtu conversion factor (roughly 25,000) is a conversion of pounds to MMBtu, which she then multiplied by 2,000 pounds per ton. This explains why her coal prices were nearly twice the actual forward prices.[2] This has the effect of dramatically raising the dispatch price of all coal-fired generation in her analysis.

Third, Ms. Frayer (pages 34-35 of original testimony) criticizes my assumptions about the price of SO2 and NOx allowances. However, as I demonstrate in my Supplemental Testimony, the relatively minor difference between our allowance price assumptions has no impact on the analysis.

Fourth, Ms. Frayer (page 52 of original testimony) asserts that I have understated Applicants' share of the capacity market by using installed capacity as a proxy for UCAP. Her contention is that the higher proportion of nuclear generation in Applicants' generation portfolio combined with lower forced outage rates on nuclear plants means that Applicants' market shares are actually larger than I calculate. In my Direct Testimony, I acknowledged that PJM capacity markets take into account forced outage rates, but pointed to my analysis of Economic Capacity at the highest priced summer peak period as a reasonably proxy for UCAP, since it takes into account forced outages. Further, as I described in my Supplemental Testimony, her analysis is flawed because she applies an incorrect outage rate in determining UCAP. The *PJM Unforced Capacity Market Business Rules* indicate that the appropriate forced outage rate to use is EFORd (Equivalent Forced Outage Rate demand), not the EFOR (Equivalent Forced Outage Rate) that Ms. Frayer used, the practical effect of which is to cause her to understate the capacity on many unit types, particularly combustion turbines. As I demonstrated in my Supplemental Testimony, proper restatement of the ICAP market to UCAP capacity levels does not materially change Applicants' market share.

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2 "Exhibit 7.xls" in Ms. Frayer's workpapers contains a table showing her conversion of NYMEX forward prices in $/ton to the $/MMBtu used in the model. It indicates that a conversion rate of 28,000 was used. I presume that this was meant to be 28 million Btu/ton. However, she appears to have confused Btu per ton with Btu per pound. No coal in the world has a heat content approaching 28,000 Btu per pound. In any event she converts to $/MMBtu by first dividing the price by 28, then multiplying it by 2. This converts the price for, for example, July 2006 from $56.75/ton to $4.05/MMBtu. In fact, the contract heat content for Central Appalachian coal is 12,000 Btu/pound, or 24 million per ton. The correct price would have been $2.36, not $4.05.

Q. Does Ms. Frayer address these errors in her FERC Supplemental Testimony?

A. In some fashion. Her explanations for errors in her prior analysis, however, are unconvincing: (1) the reason that her testimony on new entry and retirements did not match her exhibits and workpapers was because changes to the exhibits and workpapers "were inadvertently not saved" (Supplemental, footnote 49); (2) her error in the calculation of coal prices (that yielded prices nearly double forward prices for coal) is due to a "typographical error" (Supplemental, page 32); and (3) she intentionally used EFOR as the outage rate rather than the correct EFORd rates based on her "professional experience" (Supplemental, page 45), notwithstanding that PJM rules specifically state that EFORd applies for purposes of determining UCAP.

She also adds what she terms a "catalogue" of possible errors in my generation databases, several pages of inconsequential adjustments she makes to my database.[3] While Ms. Frayer (Supplemental, page 34) may be implying that these "corrections" to my database had a material effect on the Delivered Price Test ("DPT") results, I am certain they do not, and she conducts no analysis to this effect. Instead, her results reflect not only corrections to my database but also the correction of her own significant errors made in her initial analysis of the database (such as fuel prices). None of the corrections to my database has a material effect on the results: (1) to the extent ownership changes move generation from one owner to another, the market HHIs might be <u>slightly</u> different, but there is no effect on HHI changes resulting from this merger; (2) to the extent plants were incorrectly located, according to Ms. Frayer's analysis, the only potential relevance is that I understated slightly generation located in PJM East (meaning that the effect of the merger on PJM East was overstated in my analysis) or overstated slightly generation in PJM Expanded; and (3) while differentiating between ICAP and energy may be sensible, because some units do not qualify to provide capacity, the amount of such generation,

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[3] I note that Ms. Frayer did not provide an alternative database, but merely describes adjustments that she would make to my database.

particularly in PJM East, is small. as is clear from a comparison between my Exhibits J-7 and J-9.[4]

The robustness of the FERC-style structural analysis is demonstrated by the fact that even the large differences between Ms. Frayer's erroneous coal prices and mine make little difference. In order to materially misstate the effect of a merger on market shares of economic capacity, it is necessary to change the ordering of plants on the supply curve. For example, an error that made coal-fired generation more expensive than gas-fired generation could lead to a misestimate of economic supply. However, the real world fact is that even an artificial doubling of coal prices does not have this effect. Nor, of course, does it change the rank ordering of coal plants, whose costs vary primarily based on heat rates and environmental costs. The types of inputs about which she cavils will not materially affect the analysis.[5]

Assuring a wide range of price conditions, and consistency between the price conditions and the supplies that are economic at those prices, is a necessary but not sufficient condition for a proper structural analysis of a merger. It also is necessary that mitigation (generation divestiture) be analyzed on a basis consistent with market prices and input fuel costs. As discussed below, failure to do this is a further and critical flaw in Ms. Frayer's (and other witnesses') analyses.

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4 The primary difference between the two exhibits is outages (reflected in my DPT analysis, but not the ICAP analysis).

5 Dr. Kalt, while less strident, also contends that it is important that price levels analyzed be the actual average price levels for each time period in order to assure "that the unique supply mixture available during each particular season is properly accounted for in the analysis" (page 32). In fact, other than seasonal derates, that affect all units to similar if not identical extents, there are no significant differences in seasonal supply mixture. (Some coal-fired plants have additional environmental costs in the summer, but the merit order does not change.) Seasonal differences in economic supply primarily reflect price differences (highest prices in the summer, lower prices in winter, still lower prices in the shoulder) so that modeling economic capacity at a wide variety of prices provides more rather than less useful information.

Choice of Market Prices

Q. Is there a valid argument that your results are somehow undermined by your choice of market prices?

A. None whatsoever, and FERC agreed.

> Applicants have adequately addressed the protests concerning the fuel cost and wholesale market price assumptions in their analysis of energy markets. Dr. Hieronymus' fuel cost and market price assumptions are consistent in that the assumed market price corresponds with the running costs of the units most likely to set the market-clearing price in the PJM energy markets for the given season-load conditions. We agree with Applicants that the fact that Dr. Hieronymus and Mr. Frame used different fuel cost and market price assumptions, but arrived at very similar results, indicates that the results are not sensitive to changes in fuel cost and market price assumptions. Moreover, the consistency of Dr. Hieronymus' results across various assumed market prices shows that the results of the analysis are robust. In addition, the PJM MMU Study largely confirms the accuracy of Applicants' results, finding similar pre-merger and post-merger concentration levels. [footnote excluded] [6]

FERC understood that the purpose of requiring 10 price levels/time periods is to assure that the analysis results are robust over the full range of market conditions. To this end, I deliberately created a quite broad range – from a price lower than generally occurs in the market, to a price above that which generally occurs in the market. I also deliberately created more points in the interval between than would be necessary if I merely used average prices for the time periods. In any event, as I stated earlier, market prices are not a stand-alone assumption driving the screen results. It is the interaction between assumed prices and costs that determine what generation is economic at various market prices. If one analyzes a full range of market prices, as I did, the results of the Competitive Analysis Screen reflect a full range of results. In total, I analyzed prices at $20, $25, $30, $45, $55, $65, $80 and $250/MWh. There are no intentional – and certainly no obvious – price gaps in this range.

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6 *FERC Merger Order* at Paragraph 125.

Further, this issue was overblown by Ms. Frayer's incorrect fuel costs. As I described in my original testimony at FERC (page 36) I chose my market prices by considering historical PJM market prices and adjustments to account for changes in fuel costs and to reflect a broad range of market prices. In Dr. Kalt's testimony in this proceeding, his Exhibit JPK-9 shows that other than the artificially low prices that I deliberately used for the shoulder (spring and fall) and winter off-peak hours, the prices I used were quite close to those that he derives from PJM data.

The flaw in [redacted] the argument that different prices could mean that Applicants have a higher market share and therefore a higher HHI change to mitigate lies in the fact that [redacted] Ms. Frayer [redacted] misrepresents the connection between market prices, dispatch costs and mitigation: if the market price is higher and more of Applicants' generation is economic, one needs to take account of Applicants' commitments that include this higher cost generation. This is evident from my response below to Ms. Frayer's supplemental testimony on this point.

Q. How did Ms. Frayer misinterpret mitigation in the context of her criticism of your market prices?

A. Repeating an error she made in her initial analysis, Ms. Frayer misapplies Applicants' mitigation commitments, which results in her conclusion that significantly more mitigation is required. Leaving aside her analyses that assume all of the divested capacity is purchased by the largest current market participants (which reflect the initial proposed buyer restrictions) her Exhibit 38 reflects her misapplication of Applicants' proposal. She says (Supplemental, page 36):

> ...in my analysis, nuclear capacity in Dr. Hieronymus' Exhibit J-13 was attributed to all market segments, while coal was assigned to "Rest of Peak," "Top 10% of Peak," and "Super-Peak" periods. Mid-merit capacity from Dr. Hieronymus' Exhibit J-13 was assigned to "Top 10% of Peak" and "Super-Peak" periods, and the peaking capacity was assigned to the "Super-Peak" period only. This was a reasonable allocation given the level of information that Dr. Hieronymus provided in his own analysis and my forecast dispatch prices vis-à-vis the diversity of the generating asset pool that included the assets available to be divested.

She apparently fails to understand that my mitigation calculations are based on the economics of supply, not a rigid – and incorrect – adherence to a time period. If coal-fired generation is economic at the price level analyzed, then the mitigation that includes coal-fired generation must be taken into account.

Ms. Frayer's mistake is as follows. In my analysis of the Shoulder Off-Peak periods, I assumed a market price of $20. At this price, Applicants' coal-fired capacity was not economic, so the quantity of mitigated capacity that I assumed in calculating the post-merger HHI did not reflect the proposed divestiture of coal-fired capacity. In the alternative analysis of the Shoulder Off-Peak period offered by Ms. Frayer, she calculates a market price of $45, which makes the coal-fired capacity economic. She accounts for the impact of the higher price on the market size and Applicants' capacity that is economic at this price, but she fails to account for the larger amount of Applicants' divested capacity that would be economic at the higher price. The discrepancy is clearly seen in the market size. In my Shoulder Off-Peak period, the only units that are economic (in addition to hydro and must-take) are nuclear plants, and hence the market size is 14,180. In contrast, in Ms. Frayer's Shoulder Off-Peak period, in addition to nuclear plants (and hydro and must-take), some coal plants are economic, and hence her market size is 4,190 MW greater than mine. Further, Applicants' own more economic capacity when coal-fired units are economic, so their pre-divestiture market shares are higher. Ms. Frayer points to the fact that Applicants have a higher market share, but then ignores entirely Applicants' commitment to divest 550 MW of coal-fired generation in PJM East (equivalent to 396 MW derated capacity in the Shoulder period). Her HHI calculations therefore assume that Applicants will continue to own coal-fired capacity that they have committed to divest.

The bottom line: if Ms. Frayer had accounted for Applicants' mitigation commitments consistent with her assumed market prices, she would have concluded, as did FERC, that Applicants' mitigation is sufficient.[7]

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[7] As FERC concluded: "In both studies, FirstEnergy's witness, Ms. Frayer, understated the amount of the proposed mitigation in various seasons because she assumed a lower price in the mitigation scenario than in the post-merger-

Q. Does Dr. Kalt make similar mistakes in arguing that you have "knife-edge" results?

A. Yes, but Dr. Kalt's analysis also suffers from some more basic flaws. Dr. Kalt argues that my analysis is not sufficiently robust because small changes in a unit's cost will change the economics of the unit, which in turn will make the proposed mitigation insufficient. He provides as an example the Bergen units, whose projected variable costs are near $55/MWh, which is the market price I consider in my analysis of the Winter Peak and Summer Peak periods. (Although he says that this example can extend to other units, he provides only one other, inapt, example.) He argues that a minor increase in the Bergen units' variable costs (from a higher heat rate or a higher gas price) would make these units uneconomic at $55/MWh (plus 5 percent). He claims that if the Bergen units were uneconomic at $55/MWh and if they were divested to satisfy part of Applicants' mitigation commitments, those commitments would not eliminate the screen failures in some periods.

The premise of Dr Kalt's example is that the variable costs of Bergen, and no units "like" Bergen, are understated. He provides no evidence that this is the case; he merely posits it as a hypothetical. In my analysis, the variable cost of the Bergen units Dr. Kalt references is $55.88/MWh. The Bergen units would be uneconomic in the periods of interest if their costs were greater than $57.75/MWh, which would imply that I had understated their costs by more than 3 percent. Dr. Kalt offers two reasons why Bergen's variable costs might be understated: (1) "poorer-than-assumed thermal efficiency"; and (2) "natural gas contracts to the operator that turn out to be only slightly more costly than for others." With respect to the plant's thermal efficiency, he does not explain what malady might affect the Bergen units uniquely among combined cycle units in the region. With respect to the cost of natural gas, I simply note that if market fuel costs increase, market prices would also increase and hence Bergen's relative position would be unchanged. A contract at above-market prices does not alter the incremental cost of the unit, which is typically determined based on market prices. If a higher-than-market

without-mitigation scenario, thus not giving credit for some of the units being divested. In short, divested units that were "economic" were incorrectly considered "uneconomic" by Ms. Frayer." FERC Order, Paragraph 133.

contract is take-or-pay, the incremental cost for the gas is zero. If it is not a take-or-pay contract, a generator would buy gas at market prices rather than take above-market gas.

Setting aside the question of whether the Bergen units' variable costs might be uniquely increased, Dr. Kalt's analysis of the implications of such an increase contains several errors. Dr. Kalt's hypothetical, properly analyzed, does not result in screen failures once Applicants' proposed mitigation is accounted for. Dr. Kalt's first error is similar to Ms. Frayer's. The time periods in my analysis with $55/MWh market prices require the mitigation that they do because of the amount of Applicants' capacity that is economic at that price. Removing Bergen from the market by pricing it out of the market would reduce Applicants' economic capacity during those time periods by the same amount as divesting it. For example, I assumed that Applicants own 11,052 MW of generation capacity in PJM East, including Bergen, in the Summer Peak period. If, as Dr. Kalt hypothesizes, Bergen were not economic during the Summer Peak period, then I would have to reduce the amount of generation owned by Applicants in this period by 1,113 MW (the derated summer capacity of Bergen), which would reduce their ownership of generation to 10,039 MW. Dr. Kalt incorrectly assumes that Applicants would continue to own 11,052 MW of capacity in the Summer Peak period notwithstanding his assumed change to the Bergen units' costs.

There are three additional problems with Dr. Kalt's analysis: (1) his analysis does not reflect Applicants' additional mitigation commitments; (2) he did not account for the derating of the Bergen units due to outages; and (3) in his analysis of the PJM East market, he incorrectly reflected Applicants' mitigation commitments.[8] These errors lead Dr. Kalt to an incorrect conclusion.

Dr. Kalt cites the Eddystone plant as an additional example. He argues that if Eddystone were uneconomic in the Winter and Summer Off-Peak periods, Applicants' proposed

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[8] Dr. Kalt apparently misunderstood the level of divestiture that I assumed at the $55 per MWh time period. My analysis reflected 650 MW of divestiture for generation such as Bergen in PJM East. In adjusting for the exclusion of Bergen from the $55/MWh time period in his analysis, Dr. Kalt eliminated 1,200 MW of divestiture in PJM East.

divestiture would be ineffective. In fact, the Eddystone plant is uneconomic in the Summer Off-Peak period as reflected in my analysis, so his adjustment to my analysis of that period is without basis. The plant would be uneconomic in the Winter Off-Peak period only if its cost were 20 percent higher than I estimate it to be, as shown in Table 1. The dramatic cost increase that Dr. Kalt assumes is purely hypothetical – he suggests it could be the result of a "minor" fuel cost change.[9] In addition, he makes the same errors in his analysis of the impact of this increase in Eddystone's costs that he made in his analysis of the Bergen plant. Importantly, it is precisely because Eddystone is included as economic supply in the Winter Off-Peak period that Applicants' proposed mitigation includes a requirement to divest some coal-fired generation. Again, I believe Dr. Kalt is falling into the same trap as Ms. Frayer and missing the intent of mitigation – and, indeed, the very basis for the mitigation – that where Applicants' generation is economic and causing HHI changes, appropriate divestiture will occur.

Table 1: Comparison of Market Prices to Eddystone's Variable Cost ($/MWh)

Off-Peak Period	Market Price	105% of Market Price	Eddystone Cost (average)
Winter	$30.00	$31.50	$26.48
Summer	$25.00	$26.25	$31.15

In any event, the "knife-edge" argument is an elevation of form over substance. Each of the 10 price levels that I have used is a representative snap shot of market conditions. In reality, prices vary constantly over time. The price might indeed be $55 at 10 AM but $58 at 10:30 AM and $60 at 10:45 AM. While a plant might indeed be economic at one of these prices but not others, this does not show any ability to exercise sustainable market power. Indeed, it is unlikely to demonstrate even opportunistic market power since: (1) the unit owner would not know before the fact what the precise price level (or the bids of competing units) would be; and (2) the plants being discussed by Dr. Kalt are not nearly flexible enough to vary output materially based on these transitory differences in prices.

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9 Because only the Eddystone plant's cost increases in Dr. Kalt's hypothetical, the posited fuel cost increase

[redacted]

Q. [redacted]

A. [redacted]

[redacted]

[redacted]

[redacted]

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would somehow not affect other coal-fired plants in the region.

10 [redacted]

11 [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

12 [redacted]

13 [redacted]

[redacted]

[redacted]

[redacted]

III. TRANSMISSION ALLOCATION METHOD AND FTRS

[redacted]

[redacted]

[redacted]

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14 [redacted]

[redacted]

[redacted]

15 [redacted]

16 [redacted]

17 [redacted]

Treatment of Financial Transmission Rights

Q. How do you respond to Dr. Kalt's criticism that you should have accounted for ownership of Financial Transmission Rights ("FTRs") by allocating imports into PJM East to holders of FTRs rather than using either economic or pro rata allocation?

A. Dr. Kalt treats FTRs as if they were firm transmission rights. But they are not. They are financial transmission rights. Dr. Kalt, who made a similar argument in the FERC proceeding, seems to continue to misunderstand the distinction between the physical right to import energy and the financial consequences of owning FTRs into PJM East. Owning FTRs does not convey any control over imports. In addition, FTRs are at most annual. There is longer-term grandfathering of Auction Revenue Rights ("ARRs"), which provide the rights to revenues from future auctions of FTRs, but grandfathered ARRs are tied to load obligations and not to particular companies or generating assets.

FTRs are not, as Dr. Kalt states (page 24) "in effect, import rights that give an owner the ability to take generation at a particular source outside of a particular market and 'sink,' or deliver, it at a different point or one on the system." Nor is he correct in stating (page 21) that "[c]oupled with combined Exelon-PSEG post-merger ownership of a considerable quantity of low-cost generation sources outside the congested PJM East relevant geographic market, the consideration of FTRs and associated control over imports into PJM East is of critical relevance." FTRs are financial instruments that entitle the holder to receive revenues (or incur charges) based on the hourly energy price differences across the transmission path in the day-ahead market. The purpose of a FTR is to provide market participants the ability to have price certainty when buying energy on one part of the PJM system to serve load on another part.

The value of FTRs has nothing whatsoever to do with the ownership of remote generation or how much the holder of an FTR schedules (insofar as such schedules even are permitted in PJM)[18] across an interface. FTRs are financial hedges, no different than

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[18] Indeed, Dr. Kalt's conception that FTRs provide the ability to import generation (stated at page 24 and reiterated at page 26) makes no sense within PJM. If Applicants' non-East generation is economic within the

could be obtained in bilateral derivative markets, that are wholly unrelated to rights for transmission service. As stated in the PJM State of the Market Report (page 43) "ARR and FTR holders do not need to deliver energy to receive ARR or FTR credits, and neither instrument represents a right to the physical delivery of power."

Ownership of FTRs provides no right whatsoever to preferential access to scarce transmission, nor do they allow the holder to limit or otherwise control the level of imports into PJM East. Imports into PJM East are constrained only by the 7,300 MW physical limit. Indeed, to the extent the PJM East interface is constrained, 7,300 MW will be flowing into PJM East, and these flows are separate and distinct from the holders of the FTR rights. Whenever flows are not constrained, i.e., are less than 7,300 MW, PJM East is part of a larger market and thus is not a relevant market definition.

Another reason why I did not analyze FTR holdings (much less, allocate transmission to FTR holders) is that FTR's are at most annual. Hence, current FTR holdings, which entail no grandfathering rights, are essentially useless for predicting who will hold such rights in the future. Though grandfathering applies to ARRs, Dr. Kalt errs by suggesting (page 27) that any grandfathered rights are retained in the annual auction indefinitely because they are "linked to generation and persist year after year unless specific generation is divested."[19]

As stated in the PJM State of the Market Report:

> PJM market rules automatically reassign ARRs and their associated revenue when load switches among LSEs… (page 244)
>
> Current PJM rules ensure that when load switches among LSEs during the planning period, a proportional share of associated ARRs within a given transmission or load aggregation zone is automatically reassigned to follow that load. ARR reassignment occurs only if the LSE losing load has

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PJM security constrained dispatch, it will be dispatched. It will flow wherever it flows according to the laws of physics, not some contract path right that Dr. Kalt (wrongly) associates with FTRs.

19 In addition, Dr. Kalt fails to note that grandfathered rights apply to ARRs, not to FTRs. The only sense in which ARRs are tied to generation is, as described below, that an LSE may get ARRs only to the extent it has rights to a specific generating resource.

> ARRs with net positive economic value. An LSE gaining load in the same zone is allocated a proportional share of positively valued ARRs within the zone based on the shifted load. This rule supports competition by ensuring that the hedge against congestion follows load, thereby removing a barrier to competition among LSEs and, by ensuring that only ARRs with a positive value are reassigned, preventing an LSE from assigning poor ARR choices to other LSEs. (page 248)

As such, the merged entity will not have access to a known quantity of grandfathered ARRs (or FTRs) year after year indefinitely. There are no rollover rights for ARRs – they go away when the load goes away. At best, this suggests that ARRs should be reflected in an Available Economic Capacity analysis, but not an Economic Capacity analysis. As I explained in my Supplemental Testimony, however, Applicants' additional mitigation commitments reduce the incremental Available Economic Capacity to zero (actually, negative) in all but one instance.[20]

IV. GEOGRAPHIC MARKET DEFINITION

Q. What other relevant geographic markets do interveners claim you should have considered?

A. Dr. Kalt criticizes my choice of relevant geographic markets (PJM East, PJM Pre-2004, PJM Expanded), arguing that I also should have considered PJM Classic as a relevant market. PJM Classic differs from my PJM Pre-2004 market by the exclusion of the former Allegheny Power ("AP") control area.

Q. Why is PJM Pre-2004 rather than PJM Classic properly defined as a market?

A. Dr. Kalt cites to transmission congestion and price separation to support his contention that AP is outside of the relevant market. In my Supplemental testimony, I defended my market definition based on history. Since AP's integration into PJM, PJM has operated the system so that when constraints on the AP system arise, certain generation units in PJM are re-dispatched, preserving the flows from west to east. The effect is that

[20] The exception is the winter super-peak in Expanded PJM; however, the market is very unconcentrated and the mitigation further eliminates any concerns.

congestion is managed on a PJM/AP market wide basis, thus constituting an integrated market. The PJM 2004 State of the Market Report explains:

> Prior to the integration of the AP Control Zone into PJM on April 1, 2002, the primary controlling action for these constraints had been for AP to restrict energy transfers through its system, including transfers from western resources to PJM and Dominion Virginia Power (VAP). This action had the effect of raising the overall PJM dispatch rate higher than it would have been if the transactions had not been curtailed. The result was increased energy prices for the entire PJM Mid-Atlantic Region, regardless of location. There was no impact on measured congestion because the entire PJM system was affected.
>
> After the AP Control Zone was integrated into the PJM market and the redispatch of PJM generation was used to control AP transmission facilities, a significant change in price impacts occurred. Rather than simply restricting relatively low-cost energy transfers, higher cost generating units were dispatched out of merit order (redispatched) in order to serve load in the transmission-constrained areas. As a result, the price of energy in the constrained areas was higher than elsewhere and congestion occurred. Higher LMPs resulted only at those locations directly limited by a constrained facility while lower LMPs occurred elsewhere. The PEPCO Control Zone was the most directly affected by these constrained facilities, followed by the BGE Control Zone.[21]

Based on a similar understanding of a market that is now economically integrated, FERC accepted my market definition.

> We reject arguments that "PJM-Classic" should be considered a separate relevant geographic market within PJM Pre-2004. We note that the PJM MMU report does not consider PJM-Classic as a separate market, and no one has shown that there are frequent binding transmission constraints that isolate PJM-Classic from the rest of PJM Pre-2004.[22]

In support of his market definition, Dr. Kalt notes historical price differences across PJM generally and between the AP zone (located in PJM Pre-2004 but not in PJM Classic) and

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[21] PJM 2004 State of the Market Report, pages 218-219. While I am citing here to the most recent PJM State of the Market Report, this same statement is included in the 2003 State of the Market Report, page 166. The 2003 Report was published prior to my original testimony; the 2004 Report after my testimony.

[22] FERC Merger Order, Paragraph 123.

the PEPCO zone (located in PJM Classic), and between the AEP zone (located outside of PJM Pre-2004) and the FE Penelec zone (located in PJM Classic).

His comparison of prices between AEP and a location in PJM Classic is irrelevant. There is no dispute that AEP is not part of either PJM Classic or PJM Pre-2004, and my analysis has not assumed that it is. Furthermore, the information in Exhibit JPK-2 supports the conclusion that PJM East is a separate market, and I have treated it as such. Dr. Kalt presents two pricing zones that are in PJM Classic but not in PJM East: the PEPCO and FE-Penelec zones. He then focuses solely on price differences between the AP zone (outside of PJM Classic) and the PEPCO zone (inside of PJM Classic). However, his Exhibit JPK-2 also reflects price separation between the PEPCO zone and other zones within PJM Classic. These data merely suggest that PEPCO may sometimes be in a constrained market that separates from both AP and FE Penelec in western and central PJM. Applicants own no generation in the PEPCO zone, so this is irrelevant to an analysis of this merger.

Dr. Kalt also fails to note that the AP zone (in PJM Pre-2004) and the FE Penelec zone (in PJM Classic) are interconnected, and that prices in the AP and the FE Penelec zones are essentially the same ($47.51 versus $47.47). This suggests that it is reasonable to include the AP zone, along with the FE Penelec zone, in the same market.

Dr. Kalt also cites to an analysis I provided in a discovery response that did analyze the PJM Classic "market." That discovery response is attached to his testimony as Exhibit JPK-11. He focuses on (and extracts to create his Exhibit JPK-4) an analysis that assumes that the divested generation was sold to the four largest generation owners. This is consistent with my FERC Supplemental Testimony Exhibit J-29. Unsurprisingly, the slight reduction in market size when AP generation is excluded creates screen failures for the smaller market. But these screen failures occur only if large current market participants acquire the divested generation. This is demonstrated by the other analysis that I provided, contained also in his Exhibit JPK-11, that shows no screen failures in PJM Classic under the original, more constrained rules for who could buy divested generation. Thus, even if PJM Classic is a proper market, a point on which Dr. Kalt and I clearly disagree, the screen failures will occur only if a substantial portion of the divested generation is sold to large current market participants.

The third piece of evidence Dr. Kalt marshals in favor of the idea that PJM Classic should have been analyzed is the extent to which the Bedington-Black Oak line is constrained. Bedington-Black Oak is a line located within AP (not between AP and PJM Classic) that can become overloaded as large amounts of low cost generation to the west of it seeks to flow eastward into higher-priced markets. Dr. Kalt is correct that the Bedington-Black Oak line is constrained at times.[23] However, as noted earlier, PJM re-dispatches around this constraint to the extent possible to preserve flows west to east and hence minimize price differences. Further, the Bedington-Black Oak constraint is a high priority "fix" that PJM is seeking to address.[24]

V. [redacted]

Q. [redacted]

A. [redacted]

Q. [redacted]

A. [redacted]

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[23] Dr. Kalt also cites to testimony of his colleague, Dr. Tranen, to argue that within-PJM congestion has increased over time. This is disputed by the PJM State of the Market Report: "During 2004, constraint frequency on the main operating interfaces affecting large amounts of PJM load was reduced considerably." (page 216)

[24] "The Black Oak – Bedington 500 kV circuit exceeds the reactive limit (voltage problem) for the outage of Pruntytown – Mount Storm 500 kV circuit. PJM is continuing to work with AP to identify the appropriate system upgrade." PJM *2004 Baseline RTEP Report*, For the 2005 - 2009 Period, July 11, 2005.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Q. [redacted]

A. [redacted]

Q. [redacted]

A. [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Q. [redacted]

A. [redacted]

[redacted]

[redacted]

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[25] [redacted]

[26] [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Q. [redacted]

A. [redacted]

Q. [redacted]

A. [redacted]

27 [redacted]

28 [redacted]

[redacted]

[redacted]

Q. [redacted]

A. [redacted]

Q. [redacted]

A. [redacted]

[redacted]

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29 [redacted]

30 [redacted]

[redacted]

[redacted]

[redacted]

Q. [redacted]

A. [redacted]

Q. [redacted]

A. [redacted]

VI. MITIGATION

The Efficacy of Virtual Divestiture

Q. What is the basis for interveners' claim that virtual divestiture is not effective mitigation?

A. The two primary concerns relate to ongoing operational control and difficulty in ongoing monitoring. Dr. Kalt argues that the fact that nuclear facilities will remain under the control of Applicants means that the theoretic incentive to withhold will remain and there is too much uncertainty about Applicants' approach. [redacted] FERC rejected [redacted] this argument.

FERC points out that operational control is not dispositive of market power in this instance. Certainly, it cannot be argued that Applicants retain control of the energy that is being divested.

> 134. Protestors raise numerous issues regarding the effectiveness of Applicants' proposed virtual divestiture of 2,600 MW of energy from nuclear capacity. In particular, many protestors argue that the Commission should only accept actual, physical divesture as effective mitigation. However, as stated above, there are a number of possible effective market power mitigation tools, and we have recognized that different options can be reasonable for a given set of circumstances. We have recognized that operational control of generation resources is a key element of market power analysis and mitigation. Here, the virtual divesture effectively transfers control of the output of 2,600 MW of nuclear capacity from the merged firm to the purchasers. That is, the merged firm cannot withhold the energy from the market and the buyer of the firm rights, not the seller, determines where and to whom the energy is ultimately sold. Applicants have committed to sell all of the energy that is offered, regardless of the price of the bids, and that an independent auction monitor will oversee Applicants' compliance with that commitment. Moreover, the liquidated damages provisions in the contracts, reduce the merged firm's incentive to withhold output to drive up wholesale energy prices because it would be contractually obligated to pay the cost of any price increase. In effect, the virtual divestiture is a must-offer provision that removes the ability to withhold output, along with a contractual provision that reduces the incentive to withhold output in order to affect market outcomes. As we have said in numerous contexts, we are concerned about a merger's effect on the merged firm's ability and incentive to harm competition. Furthermore, as a condition of the Commission's approval, Applicants must agree that, if the virtual divestiture does not in fact mitigate the problems identified, Applicants will propose to the Commission mitigation that will mitigate the problems identified.

Dr. Kalt argues that Applicants will have an incentive to prolong outages. However, because Applicants still need to meet the obligations under the virtual divestiture sales, such incentive is not present. That is, they would have to replace the missing output via purchases from the market at much higher costs than the variable cost of production from nuclear facilities.

FERC further notes the possibility of withholding nuclear generation is quite small, and that Applicants' commitment to have a monitor overseeing compliance further ensures that the virtual divestiture is implemented properly.

> 135. Protestors also object to the virtual divesture on the grounds that it will be difficult to monitor. For example, AAI notes that the antitrust agencies prefer physical divestiture because it removes the need for ongoing monitoring. We recognize that concern, but find two critical factors supporting virtual divesture as a reasonable alternative to physical divestiture. First, as we have stated in a number of cases, the operational characteristics of, and regulatory scrutiny over, nuclear units virtually eliminate the possibility of withholding output to drive up prices. Second, Applicants have committed to establish an independent monitor to oversee the auction itself and Applicants' compliance with the contracts, and Applicants will establish a public compliance website that will show how they are complying with the virtual divestiture and other mitigation requirements. We rely on those commitments in our finding that the virtual divestiture effectively mitigates the merger-related harm to competition. We will direct Applicants to make a compliance filing within 30 days of this order, detailing the process for the selection of the independent monitor.

[redacted] Mr. Kalt argues that strategic bidding of nuclear units in spot markets would increase forward prices, and that retiring units would increase forward prices.[31] These would be risky strategies in any event in a market as competitive as PJM. Moreover, the theory is at best questionable and speculative. In order for withholding nuclear capacity to affect the price for three-year forward contracts, buyers in the bilateral market would have to believe that the withholding would persist for the duration of the contracts. Indeed, due to the rolling nature of the contracts, with only 800 MW subject to recontracting annually, it would have to be a permanent ongoing strategy. No showing is made, and likely none could be, to demonstrate that withholding nuclear capacity in order to induce higher prices for the nuclear auction would be profitable.[32] Dr. Kalt argues that withholding mid-merit supplies may lead to higher going-forward prices, pushing up prices in any future contracts; he is also arguing that Applicants would be willing to incur short-term costs for the dubious possibility of higher long-term profits.

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[31] Ms. Frayer also argues that virtual divestiture should not be subject to reduction due to retirements.

[32] The assertion that Applicants would engage in a strategy of withholding output from their nuclear facilities is particularly ironic in view of the fact that a major source of benefit from the merger is the improvement in the level of output from the nuclear units.

Further, as FERC reiterates, long-term capacity markets are competitive. Capacity withholding, even if it were permanent (due to irreversible retirement) or otherwise expected to persist, would likely result in an increase in entry that would prevent a sustained increase in prices. Finally, the argument ignores Applicants' commitment to divest an appropriate level of mid-merit units that is intended to eliminate any increased ability or incentive of Applicants' to withhold such units. As FERC stated:

> We reject FirstEnergy's assertion that Applicants will receive the same price for the virtually divested energy as they would have in the absence of mitigation. First, as argued by Applicants, under the virtual divestiture plan, Applicants will receive the price determined in the auction for the three-year life of each contract, whereas if they retained control of the output of the nuclear units, they would be able to benefit from any market price increases during the same three-year period. Second, by giving up control of 6,600 MW of through the divestiture and virtual divestiture, Applicants have adequately mitigated the merger-related increase in market power. Therefore, they would not be able to raise the price of energy by other means, as the previous contracts expire, in order to raise the price they receive for the three-year contracts.

Finally, FERC also rejected intervener arguments about the effect of retiring existing generation.

> Applicants have also made a convincing argument that a decrease in their nuclear capacity, whether through divestiture, de-rating, or unit retirement, would mitigate market power, because the incentive to withhold output is an increasing function of the amount of baseload capacity from which the merged firm could profit due to higher energy prices. Therefore, by reducing the amount of baseload capacity they control, they reduce their incentive to withhold marginal capacity in order to raise the market price.

Q. [redacted]

A. [redacted]

[redacted]

Elimination of Purchaser Restrictions and Identification of Units to Divest

Q. Some interveners continue to claim that that Applicants' elimination of its prior restrictions on who can buy the divested capacity is still not sufficient. Please comment.

A. The protests generally arise from [redacted] an unwillingness to rely on Applicants' compliance filing [redacted] in conjunction with the FERC's condition (Paragraph 132) that Applicants demonstrate that mitigation will "reduce market concentration to within the screening tolerance for increases from the pre-merger concentration level."

[redacted]

Ms. Frayer [redacted] simply rejects the assumptions I use to model who buys the divested capacity, and posit an alternative set of assumptions to indicate that if only current large owners in PJM buy the divested units, the screens will continue to show higher than acceptable HHI changes.[34]

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[33] [redacted]

[34] I note that Dr. Kalt apparently accepts Applicants' commitment to eliminate purchaser restrictions. The only concern he raised in his testimony was applicable only if FERC had set the merger for hearing, which it did not.

All of these arguments are mooted by Applicants' commitment to, and FERC's condition requiring, a compliance filing that consists of re-filing a Competitive Analysis Screen to reflect the specific units being divested and the specific buyers of the divested units.

This having been said, it is useful to put some of the concerns to rest. [redacted] Applicants have agreed to sell the divested units (as well as conduct the virtual divestiture) irrespective of the prices that they are offered. They have a candidate list of divestible plants much larger than the divestiture requirement. Their commitment is well known to the market well in advance of the closure of the transaction that begins the 12-month clock. Under these circumstances, there is no plausible basis to conclude that the divestiture will not go forward as planned.

These witnesses also argue that it is necessary to know the specific units to be divested. This same argument was made at FERC and soundly rejected.

> 141. A number of protestors argue that the Merger Policy Statement requires Applicants to identify the specific units that will be divested... While the Merger Policy Statement does state that applicants must identify the specific units to be divested, in this instance, we find Applicants' proposal sufficient because the divestiture can adequately mitigate the merger-related harm to competition; moreover, once the specific units have been identified, we will be able to ensure that they are appropriate units to make divestiture effective through the subsequent compliance filing discussed above... (footnotes omitted)

[redacted]

[redacted]

Q. Dr. Kalt argues (page 37) that it would be poor public policy to limit what existing large market players, particularly his client, PPL, would be permitted to buy. He refers to this as "imposing buyer restrictions that predetermine the post-merger marketplace structure." What is your response?

A. I note that the question posed by Dr. Kalt was premised on whether FERC initiated a hearing on the merger. (He asks himself (page 37) "Do you have concerns about the merging parties' proposed buyer restrictions in the case the FERC initiates a hearing?") The issue of buyer restrictions existed only because Applicants' commitment to eliminate its originally-proposed buyer restrictions was contingent upon FERC's approval of the merger without a hearing. Since FERC approved the merger without hearing, accepted Applicants' mitigation commitments and required a compliance filing to demonstrate that the divestiture meets the requirements of a competitive analysis screen, the issue Dr. Kalt raises is no longer pertinent.

Q. [redacted]

A. [redacted]

Q. [redacted]

A. [redacted]

Q. [redacted]

A. [redacted]

[redacted]

[redacted]

Ongoing Monitoring

Q. Separate from the compliance filing, will this merger be subject to ongoing market monitoring?

A. Yes, and I understand that Mr. Jack Crowley addresses the effectiveness of the PJM Market Monitoring Unit ("MMU") in monitoring the behavior of market participants in PJM (PECO Statement No. 9-R). I will not repeat his analysis here, but note that PJM's market monitoring and mitigation plans overall have proved effective, as evidenced by the competitiveness of PJM markets. PJM's State of the Market Report is replete with evidence that prices in PJM are at very competitive levels. Much of the time, market power cannot be exercised simply because of strong competitive forces. At other times, it might be theoretically possible to exercise market power, but knowledge that the attempt automatically would be defeated by the market rules means that the attempt is not made and the mitigation measures thereby are not invoked.

In addition to ongoing monitoring by the PJM MMU, FERC's Office of Market Oversight and Investigations ("OMOI") also has responsibility for ongoing oversight of electricity markets. One of FERC's top priorities remains to "Protect customers and market participants through vigilant and fair oversight of the transitioning energy markets."[35] To that end, OMOI's mission is "to guide the evolution and operation of energy markets to ensure effective regulation and to protect customers through understanding markets and their regulation, timely identification and remediation of

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35 Strategic Plan FY 2004-2008. http://www.ferc.gov/whats-new/top-priorities.asp

market problems, and assured compliance with [FERC's] rules and regulations."[36] To this end, OMOI has an extensive team of staff that "monitors the energy marketplace for potential problems and works to achieve corporate compliance" and "probes market developments to detect anomalous or suspicious activity, such as attempts at market manipulation or inappropriate communications or improper cooperation between market participants."[37]

Among the OMOI's recent activities have been the settlements with many participants in the California refund proceedings and the completion of dozens of separate investigations and financial audits. OMOI also has focused on compliance by electric utilities and interstate natural gas pipelines with the Standards of Conduct for Transmission Providers under Order No. 2004. OMOI also maintains a Hotline as an informal means for market participants to resolve disputes and raise questions with FERC staff.

Q. [redacted]

A. [redacted]

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[36] FERC Staff Report, "Energy Market Oversight and Enforcement," March 2005, page 4.

[37] *Ibid*, page 5.

[38] [redacted]

[redacted]

VII. VERTICAL MARKET POWER ISSUES

Q. Have you reviewed the testimony and analysis of Dr. Carpenter?

A. Yes, but I am responding to it only in part. I understand that Dr. John Morris (PECO Statement No. 11-R) also is responding to Dr. Carpenter.

Dr. Carpenter performed an alternative market concentration analysis for the PJM East delivered natural gas market and claims that the post-merger market concentration will be above the 1,800 threshold. I disagree with his characterization of the market and believe his analysis and approach are fundamentally flawed.

Q. How has Dr. Carpenter approached the analysis?

A. I note first that the FERC analysis requires that both the upstream and downstream markets are highly concentrated (HHIs greater than 1800) to conclude that the conditions for exercising vertical market power are present. In the downstream analysis, gas-fired generation is attributed to the pipeline that serves it. Dr. Carpenter states (page 15) that I had conceded that downstream markets were highly concentrated and hence he provides no analysis of the downstream part of the test. In fact, in my FERC Direct Testimony, I found that there were relatively minor screen failures in 3 of the 10 time periods (two in the summer totaling 10 percent of summer peak hours and one affecting 10 percent of winter peak hours)[39] in the PJM East market and no screen failures in the PJM Pre-2004 and PJM Expanded markets. I also noted that if some of the divested capacity were oil-fired these super-peak period screen failures could well go away. Because of the minor

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[39] Since summer and winter are half of the hours and 47 percent of hours are peak hours, the number of hours affected is about 2 percent of the total. Moreover, since PJM East is constrained away from PJM Pre-2004, only a small fraction of the time (this being the only time that PJM East is a market), the number of hours affected by these screen failures truly is miniscule.

screen failures in the PJM East, I performed the upstream analysis. While Dr. Carpenter regards the minor screen failures as dispositive of downstream market concentration, FERC found otherwise. It stated twice that my analysis had shown that the relevant downstream markets were not highly concentrated (Paragraphs 200 and 203 of its Order). The basis for FERC's conclusion is not stated, but one could speculate either that 1) FERC finds the unconcentrated state of the markets other than PJM East to be persuasive, and/or 2) FERC finds the small screen failures affecting only a small number of hours for PJM East should be disregarded. While I do not, for these reasons, regard the concentration of the downstream market to be a settled matter, as Dr. Carpenter does, I nonetheless will focus my rebuttal solely on the upstream market analysis.

Dr. Carpenter states that he started with the data and analysis I presented in my FERC Direct Testimony and made three adjustments. The first adjustment was to include some additional contracts that I had not included in my analysis, and to exclude some contracts I had included in my analysis. Next, he excluded contracts that have primary delivery points into the Algonquin pipeline (such delivery points are in PJM East). Finally, Dr. Carpenter has changed how market shares are calculated. Rather than focusing on the physical pipeline capacity that serves the PJM East market as FERC requires, Dr. Carpenter's has sized the market to include only the firm contracts with primary delivery points in the market (rather than the total inbound capacity of the transmission pipelines). His market share for each customer is its share of the total of all contracts that have primary firm delivery points within the PJM East market. He has not considered any potential residual, unsubscribed capacity on any pipeline, nor has he considered the capacity owned by shippers that can deliver into downstream markets that can be delivered into the PJM East market on a firm basis. This final difference is the most significant, and is ultimately what drives his conclusions.

Q. Why is this difference so significant?

A. The main argument put forth by Dr. Carpenter concerning the calculation of the HHI essentially mirrors the argument put forth by Dr. Briden before FERC,[40] namely that capacity "committed" to markets downstream of PJM East should be excluded from the HHI calculation for PJM East. But FERC rejected this reasoning by finding that excluding only competitor downstream capacity was a "selective omission of relevant capacity." (FERC Merger Order, paragraph 200). As I had stated in my Supplemental Testimony, in addition to the Algonquin shippers identified by Dr. Carpenter, PSEG has significant amounts of capacity deliverable to the New York citygate and which can be sold in "Transco Zone 6 New York," a market Dr. Carpenter asserted at his deposition is not part of the PJM East market.[41] In my opinion, it was appropriate to include all of the capacity into and through PJM East, which results in the upstream natural gas HHI being below 1,800, as shown in my calculations. However, if Dr. Carpenter's approach were adopted and if one were to exclude all capacity with delivery points into the New York citygate market and beyond, it would be necessary to exclude PSEG's capacity that is firm to the New York citygate in addition to the Algonquin shippers' capacity, which would also result in an upstream HHI below 1,800. Only by excluding Algonquin shippers' capacity with primary delivery points into markets downstream of PJM East but including PSEG capacity with such delivery points does one calculate a natural gas transportation HHI that is above 1,800. FERC rejected this selective omission of relevant capacity. Moreover, this approach ignores the fact that shippers holding pipeline capacity that moves through PJM East but delivers into pipelines that move the gas outside of PJM

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[40] Footnote 42 on page 21 of Dr. Carpenter's testimony cites to Dr. Briden's FERC testimony, presumably to confirm the "reasonableness of his own results. In addition to making the same error as Dr. Carpenter (i.e. eliminating contracts going through PJM East), Dr. Briden also made a major error by aggregating all small shippers as if they were a single large shipper for purposes of calculating HHIs. The errors in Dr. Briden's testimony are discussed in my FERC Supplemental Testimony, filed with this Commission.

[41] See page 27 of Dr. Carpenter's deposition (Exhibit DPO-2).

East are able to use their Part 284 open access transportation rights to deliver gas at the same delivery points as the shippers that have primary firm delivery points in PJM East.[42]

Q. What is the basis for Dr. Carpenter's exclusion of Algonquin deliveries?

A. This exclusion is consistent with his basic approach of focusing only on the set of contracts with delivery rights in the PJM East market rather than on the physical pipeline capacity serving the market. His presumption is that contracts delivering into Algonquin are ultimately routed further downstream into New York or New England on Algonquin and thus are not suppliers to the PJM East market. The list of customers excluded in this Algonquin screen is, as Dr. Carpenter notes (page 17), "largely held by New York and New England LDCs."

Q. Does Dr. Carpenter exclude the Algonquin contracts because they are held by LDCs?

A. Not explicitly, although he does seem to cite this as a rationale. Dr. Carpenter notes the large number of downstream LDCs as the customers of record to support his contention that this capacity is "largely committed to serving other markets."

Q. Do you agree that this downstream capacity should be excluded on the basis that the shippers are LDCs?

A. No. First, I'd note that most customers, either in market or downstream customers have some physical use for the gas, whether that is to serve heating load, for industrial applications, or for power generation. Only a fraction of customers are traders in the markets. This fact, however, does not alter the ability of large natural gas shippers to respond to market signals by selling gas into the PJM East market rather than delivering

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[42] Under open access transportation, shippers that pay demand charges for a transportation path obtain rights on a secondary firm basis to all other delivery points in the zones for which they pay demand charges. Secondary firm deliveries are second in priority only to primary firm shippers at the point where there is insufficient capacity at the delivery point to make both deliveries. All Transco and Texas Eastern capacity that have primary firm transportation into Algonquin, for example, are capable of delivering gas at all points within their transportation path. The combination of Part 284 capacity, along with interruptible transportation, enables secondary market transactions.

downstream. Notably, Dr. Carpenter includes local, PJM East industrials, power generators and LDCs as suppliers in his upstream analysis.

Q. Assuming that there is something unique about LDCs, does this warrant excluding suppliers with downstream delivery points from his analysis?

A. Under this hypothetical, only the volumes controlled by LDCs (as opposed to other holders of downstream receipt rights) should be excluded. However, there is no logic, even under this hypothetical to exclude only the capacity held by downstream LDCs while including capacity held by in-market LDCs.

Q. Please explain the consequence of this statement.

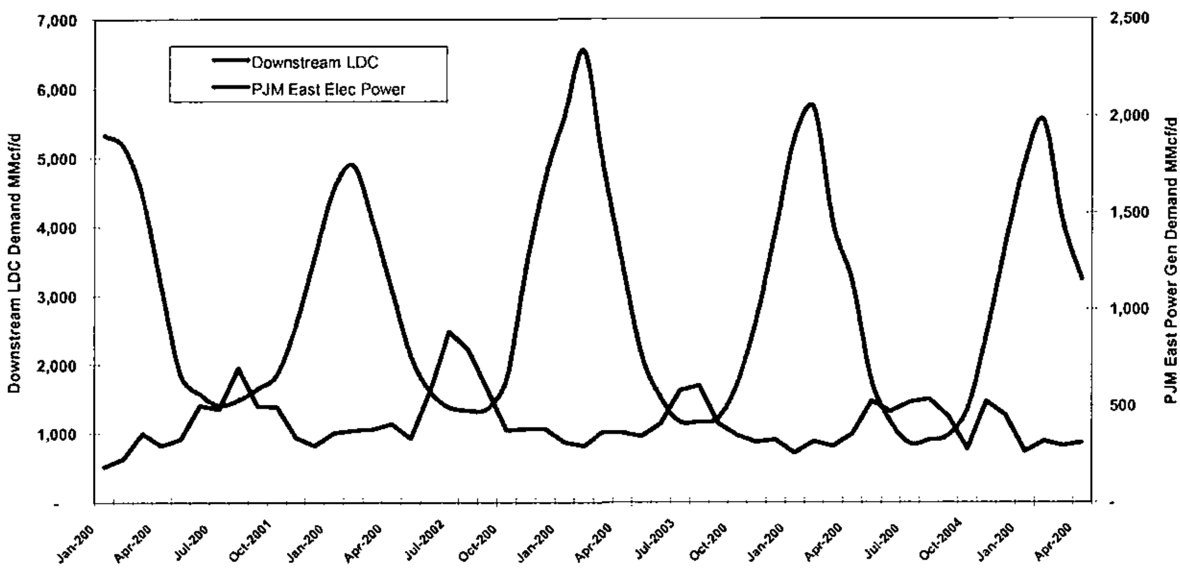
A. If the load commitments of LDCs somehow prevent them from being suppliers to generators in the PJM East market, this logic should be applied equally to LDCs located in the PJM East market. Both PECO and PSE&G (and, for that matter, PGW) are such LDCs. If all LDCs should be excluded, then Exelon's and PSEG's market shares would be very much smaller than either my analysis or Dr. Carpenter's analysis shows.

Dr, Carpenter states (page 22) that "On most days of the year this [Applicants'] capability greatly exceeds the retail gas demand that the merged entity will be required to meet, including storage injection requirements. This means that the merged entity will have 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." He goes on to concede in the following paragraph that the last clause quoted is a nullity, since capacity not used or released automatically is available on an interruptible basis. However, my main point is that exactly the same statement is applicable to all of the downstream LDCs, as Dr. Morris demonstrates.

Q. How does the seasonality of downstream demand compare with local power generation demand?

A. Local (i.e., PJM East) power generation demand peaks in the summer, precisely when downstream and local LDC demand wanes. Figure 1 charts residential and commercial demand in New England and New York against the power generation demand in Delaware and New Jersey (as a proxy for PJM East).

Figure 1: New England and New York LDC Natural Gas Consumption and PJM East Power Generation Gas Consumption (MMcf/d)



In essence, the period when a vertical foreclosure strategy would presumably be most effective, the summer, corresponds to the period when ample natural gas pipeline capacity will be available on the capacity release market or through interruptible natural gas service to deliver natural gas. The conclusion is inescapable; the capacity rights nominally pledged to downstream markets are available to play a considerable role in the competitive dynamics of the local markets in PJM East as well.

Q. Setting aside the issue of LDCs, are there any other reasons why Dr. Carpenter excluded supplies with downstream delivery points?

A. While the only expressed reason why he might have excluded them relates to their status as LDCs, another possible reason might be that both gas supplies, and hence pipeline delivery rights, are more valuable downstream. Under that hypothetical, suppliers with downstream delivery points might not deliver gas to PJM East until prices in PJM East rose significantly. Dr. Morris shows that this hypothetical is not reasonable.

Q. Assume, nonetheless, that suppliers with primary delivery points in higher priced, downstream markets do not compete effectively to moderate delivered gas prices in PJM East. Would Dr. Carpenter's analysis then be valid?

A. No. Setting aside other issues with his analysis, the point to be make here is that 794 MMcf/d of PSEG's firm transportation entitlements included in Dr. Carpenter's analysis are deliverable into Transco Zone 6 to the New York citygate (that is, beyond the constraint point on Transco).[43] If shippers who can reach this putatively more valuable destination are not effective competitors in PJM East, this would apply equally to this PSEG capacity. Thus, even under Dr. Carpenter's analysis, it was incorrect to include this capacity in his HHI calculations.

Q. What would be the effect of adjusting PSEG's capacity to remove this gas deliverable to the hypothetically more valuable market?

A. Taking Dr. Carpenter's analysis in Table 1 and correcting only this one inconsistency, the market HHI falls to the moderately concentrated range, as shown in Table 5 below.

[43] In my correction to Dr. Briden's analysis at FERC, I excluded a smaller amount, 432 MMcf/d. My review of Dr. Carpenter's workpapers suggests that he included 794 MMcf/d of PSEG's contracts deliverable past the constraint point on Transco.

Table 5: Restatement of Carpenter Table 1 (Eliminate Contracts for Delivery to NY Citygate)

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

Participant	Pre-Merger Contracts (MMcf/d)	Pre-Merger Market Share	Pre-Merger HHI	Post-Merger Contracts (MMcf/d)	Post-Merger Market Share	Post-Merger HHI
Exelon/PSEG	-	-	-	1,242	29%	831
PSEG	870	20%	408	-	-	-
New Jersey Resources	686	16%	254	686	16%	254
Exelon	372	9%	75	-	-	-
Pepco	311	7%	52	311	7%	52
Philadelphia Gas Works	295	7%	47	295	7%	47
UGI Corp	256	6%	35	256	6%	35
NUI Corporation	250	6%	34	250	6%	34
South Jersey Industries	230	5%	29	230	5%	29
NiSource Inc	215	5%	25	215	5%	25
Williams Energy	116	3%	7	116	3%	7
Dominion	97	2%	5	97	2%	5
Sunoco	93	2%	5	93	2%	5
PPL	74	2%	3	74	2%	3
WGL Holdings	68	2%	2	68	2%	2
Keyspan	55	1%	2	55	1%	2
Southern Union Company	48	1%	1	48	1%	1
Philadelphia Authority For Industrial Development	35	1%	1	35	1%	1
Amerada Hess Corporation	34	1%	1	34	1%	1
Others	202	5%	2	202	5%	2
	4,306	100%	986	4,306	100%	1,335

Q. Can you summarize why it is important not to ignore capacity flowing into PJM East that Dr. Carpenter excludes on the grounds that it is allocable to customers with downstream receipt points?

A. Ultimately, the physical pipeline capacity into a market is available to provide gas to that market should conditions warrant. As local natural gas prices rise under any hypothetical foreclosure strategy, the economics of exercising the physical option of selling into local markets such as PJM East will improve. As a result, pipeline capacity held by downstream customers must be considered in evaluating the ability of Applicants to profitably implement a vertical foreclosure strategy. Dr. Morris demonstrates that the value of gas flowing through PJM East and its value downstream rarely diverge by more than a trivial amount. For this reason, the physical location of the customer has no direct bearing on the economic decision with respect to pipeline ownership. All should be viewed as potential suppliers. Thus, ultimately, total physical pipeline capacity into PJM East must be the denominator for a true market share and HHI calculation.

Since market share is properly calculated as capacity held by a shipper divided by the total capacity in the market, clearly the size of the market is important. However, under Dr. Carpenter's approach, any capacity that is not assigned to a firm customer with primary delivery points in PJM East is simply ignored. Dr. Carpenter's approach of calculating market share relative to total in-market contracts is thus fundamentally flawed.

Q. Can you demonstrate that this approach is flawed?

A. Yes. A simple hypothetical example illustrates the shortcomings in Dr. Carpenter's approach. Consider a market with only two customers and a single pipeline serving the market. Assume the pipeline capacity serving the market is 50 percent committed to one customer under long-term, primary firm delivery rights. The second customer owns no firm capacity, nor do any downstream consumers. Dr. Carpenter's approach would show one customer with 100% market share, resulting in an HHI of 10,000, even though the remaining 50 percent of capacity is available to serve the market. Conversely, he would find that the pipeline owner had no market power, since its share would be zero. Obviously, by ignoring the *physical* capacity serving the region and focusing only on the *contractual obligations* committed to the region, significant potential sources of supply are not properly reflected. A better representation of this market would show two suppliers, the first customer with 50 percent of the region's physical capacity under a firm contract with primary delivery points and the pipeline itself with the residual 50 percent of the pipeline deliverability under its control.

Q. Apart from the issue of capacity contracted to suppliers with primary delivery points in downstream markets, per se, you stated that it is important that the market denominator should be the total capacity flowing into PJM East. Have you examined how consideration of the full physical capacity into PJM East would alter Dr. Carpenter's conclusions?

A. In reviewing Dr. Carpenter's the workpapers and the supporting data for his Table 1, I calculated the capacity rights Dr. Carpenter has considered on each of the individual pipelines. Table 6 below compares the capacity Dr. Carpenter has allocated to PJM East to the actual physical capacity into the market as presented in my direct exhibit J-16.

Table 6: Residual Pipeline Capacity into PJM East (MMcf/d)

Residual Pipeline Capacity				
Pipeline	**Owner**	**Allocated Capacity (Carpenter Table 1)**	**Total Capacity Reported in Exhibit J-16**	**Not Allocated by Carpenter**
Columbia	NiSource	635	435	(200)
Tennessee	El Paso	187	499	312
Texas Eastern	Duke	2,346	2,950	604
Transco	Williams	1,944	2,050	106
Total		**5,112**	**5,934**	**822**

Based on my estimate of the physical capacity into these markets derived from EIA data on state border pipeline capacity and flows, Dr. Carpenter has over allocated Columbia by 200 MMcf/d and under allocated Tennessee, Texas Eastern and Transco by a combined 1,022 MMcf/d. This physical capacity does not simply disappear because the shippers holding this capacity have contractual primary delivery points further downstream.

One can estimate the impact of this capacity on market concentration by assuming the pipelines themselves control unallocated capacity. Assuming, arguendo, that Columbia's capacity into the market is 635 MMcf/d as Dr. Carpenter has calculated, I have adjusted the capacity entitlements for El Paso, Duke and Williams consistent with the information above and recalculated Dr. Carpenter's HHI statistics. Under this representation, the market concentration is well below a highly concentrated market, as shown in Table 7 below.

Table 7: Restatement of Carpenter Table 1 (Unassigned Supply Assigned to Pipeline)

Include Uncommitted as Potential Supplier by Reverting it Back to Pipeline
Impact of the Proposed Exelon/PSEG Merger
on Concentration in the PJM East Delivered Gas Market

Participant	Pre-Merger Contracts (MMcf/d)	Pre-Merger Market Share	Pre-Merger HHI	Post-Merger Contracts (MMcf/d)	Post-Merger Market Share	Post-Merger HHI
Exelon/PSEG	-	-	-	**2,035**	**33%**	**1,101**
PSEG	**1,663**	**27%**	735	-	-	-
New Jersey Resources	686	11%	125	686	11%	125
Exelon	**372**	**6%**	37	-	-	-
Pepco	311	5%	26	311	5%	26
Philadelphia Gas Works	295	5%	23	295	5%	23
UGI Corp	256	4%	17	256	4%	17
NUI Corporation	250	4%	17	250	4%	17
South Jersey Industries	230	4%	14	230	4%	14
NiSource Inc	215	4%	12	215	4%	12
Williams Energy	222	4%	13	222	4%	13
Dominion	97	2%	2	97	2%	2
Sunoco	93	2%	2	93	2%	2
PPL	74	1%	1	74	1%	1
WGL Holdings	68	1%	1	68	1%	1
Keyspan	55	1%	1	55	1%	1
Southern Union Company	48	1%	1	48	1%	1
Philadelphia Authority For Industrial Develc	35	1%	0	35	1%	0
Amerada Hess Corporation	34	1%	0	34	1%	0
Others	1,130	18%	127	1,130	18%	127
Total	**6,134**	**100%**	**1,156**	**6,134**	**100%**	**1,485**

Q. Under the above representations, the total market is 6,134 mmcf/d. In your direct testimony you have a total market size of 5,934 mmcf/d. Are the conclusions impacted by this 200 mmcf/d difference?

A. No. As noted above, the additional 200 MMcf/d arises from Dr. Carpenter's allocated share on Columbia of 635 MMcf/d relative to my estimate of Columbia physical capacity of 435 MMcf/d. If I make a downward adjustment of 200 MMcf/d to NiSource's entitlements as the owner of the Columbia system, the post-merger HHI becomes 1,574 – nearly identical to the post merger market concentration I reflected in my direct testimony Exhibit J-16. Removing the 200 MMcf/d from the smallest consumers would result in a post merger market concentration of 1,586 points.

Q. Are there any other errors that you have found in Dr. Carpenter's analysis?

A. It appears that Dr. Carpenter was inconsistent in his treatment of Algonquin and Transco deliveries. At least two contracts on Texas Eastern have only Transco or downstream delivery points. Both of these contracts have Brooklyn Union Gas, a downstream LDC, as the customer of record. Both are included as providing supplies to the PJM East region in Dr. Carpenter's analysis.

Q. Do you have any other concerns with respect to Dr. Carpenter's exclusion of contracts that deliver to Algonquin?

A. Yes. Two of the customers listed in Dr. Carpenter's Table 2 are clearly companies with local PJM East interests. These two are UGI Corp and New Jersey Resources. Both are included in Dr. Carpenter's Table 1 as major suppliers to the PJM East region. While these companies have Columbia Gas deliveries at Hanover NJ, the Algonquin/Columbia interchange, neither appears on the Algonquin customer lists. And while the exclusion of these specific contracts is clearly in error, there are other instances where the general exclusion of all contracts that deliver to Algonquin also appears to be in error. There are several instances where a given contract delivers to Hanover but the excluded customer does not appear on the Algonquin customer list. The obvious conclusion is that these contracts are for local and not downstream delivery.

Q. Have you calculated the impact on Dr. Carpenter's conclusions of including these contracts?

A. Yes. By re-including this set of Algonquin deliveries lowers Dr. Carpenter's HHI statistic from 1,942 to 1,874 points.

While the impact of this oversight on his HHI results is not material, I note this because Dr. Carpenter appears to be inconsistent with his own framework. Individual contracts often have multiple delivery and receipt options. The optionality of these multiple delivery and receipt points is magnified by the portfolio effects created for customers that carry multiple contracts on the interconnected network of pipelines. The combined effect is that an ex ante determination of an *intended* physical path for the natural gas is difficult. Excluding customers, and thus excluding physical capacity into a region, based on a belief that the capacity is committed to serving other markets becomes an extremely subjective exercise.

Q. Can you provide an example to show how Dr. Carpenter's methodology can ignore the portfolio effects?

A. Yes. Suppose you have a pipeline with sequential points A, B, C and D. Points B and C are in the market. A is upstream. D is downstream. A single customer has two contracts. One contract receives at B and delivers at C. The other contract receives at A and delivers at D. Dr. Carpenter's methodology would exclude the former contract because receipt and delivery are both within the market. Dr. Carpenter would also exclude the latter contract because its delivery point indicates that it is committed to downstream markets. The complete exclusion of this customer's contracts is inappropriate even under the Carpenter framework that considers only upstream receipts and in-market deliveries.

This customer has the option to receive upstream and deliver into the market because of the portfolio effects created through the two contracts. The customer can use the receipt rights of the second contract and delivery rights of the first contract to move gas from A to C. The customer can use the receipt rights of the first contract and the delivery rights of the second contract to make opportunistic sales of gas in market D. In this example, the capacity from A into the market clearly should be included regardless of the form of particular contracts.

Q. Dr. Carpenter states that you included some contracts in the market that you should not have included and that you excluded some contracts that should have been included. Are any of these criticisms valid?

A. Yes, they are. I took these criticisms quite seriously. In consequence, I directed my staff to go back to the original source data and recheck all of the data that I used. Among the refinements that my staff was able to make, that they had not made before, was to get a more precise fix on the capacity on, for example, the Tennessee pipeline that flowed through the branch traversing PJM East, as opposed to the branch further west in Pennsylvania. This revised database is, I believe, superior to my database that Dr. Carpenter criticized and supports a better analysis than either of us had performed. My conclusions, however, are unchanged. The merger does not present any vertical market power concerns.

Q. Can you describe the changes you've made to your analysis based on your further review of the available information?

A. Yes. There are two categories of changes to my database. The first relate to capacity on pipelines physically serving the PJM East market. I have updated the pipeline capacities to reflect the most recent data available from the EIA, the 2004 year-end data. I have included an additional pipeline segment on Transco, route index LAT-SG, that delivers gas from points of interconnection with other upstream pipelines in central and western Pennsylvania to New Jersey, known as the Leidy Line. This segment adds an additional 885 MMcf/d in capacity to the region. The second category of changes relate to contracts included in my PJM East analysis. The Tennessee and Columbia pipelines both have segments that serve different parts of Pennsylvania and downstream states in New York and New England. Upon additional review of receipt and delivery point information associated with each contract, I determined the branch of these pipelines on which the contract provides entitlements. In many cases this more detailed review of the contracts allowed me to exclude contracts and customers that do not have entitlements to deliver into PJM East.

Q. Have you, indeed, performed a new analysis of the upstream market using this revised database?

A. Yes. For the reasons that Dr. Morris and I have discussed, this analysis includes customers with downstream receipt points. In acknowledgment of a comment made by Dr. Carpenter, downstream customers are included not merely for those utilizing the Algonquin pipeline, but all pipelines entering PJM East.

Q. What does this analysis show?

A. The analysis shows that post-merger concentration is squarely in the moderately concentrated range and hence does not raise any concerns with respect to vertical market power. As shown in Table 8 below, the post merger HHI is 1,292, demonstrating that the conditions for a vertical foreclosure strategy are not present.

Table 8: *PJM East Delivered Gas Market*

Customer	Capacity (MMcf/d)	Market Share	HHI
Exelon/PSEG	**1,974**	**29%**	**835**
KeySpan Corp.	1,002	15%	215
Consolidated Edison, Inc.	659	10%	93
New Jersey Resources Corp.	436	6%	41
UGI Corp.	319	5%	22
Philadelphia Gas Works	296	4%	19
South Jersey Industries, Inc.	282	4%	17
NUI Corp.	236	3%	12
Energy East Corp.	197	3%	8
PEPCO Holdings, Inc.	172	3%	6
NiSource Inc	129	2%	4
The Williams Companies, Inc.	117	2%	3
Southern Union Co.	105	2%	2
NSTAR	102	1%	2
Dominion Resources, Inc.	97	1%	2
Others	709	10%	11
TOTAL	**6,831**	**100%**	**1,292**

VIII. CONCLUSION

Q. Does this complete your rebuttal testimony?

A. Yes.