

ORIGINAL

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

A-110550 FO/60

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 - _____

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

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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

JOINT APPLICATION OF PECO	:	
ENERGY COMPANY AND PUBLIC	:	
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COMPANY FOR APPROVAL OF THE	:	DOCKET NO. A-
MERGER OF PUBLIC SERVICE	:	
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DIRECT TESTIMONY
OF
WILLIAM H. HIERONYMUS

Date: February 4, 2005

1 consider whether a proposed merger or consolidation of electric utilities or
2 electric suppliers “is likely to result in anticompetitive or discriminatory conduct,
3 including the unlawful exercise of market power, which will prevent retail
4 electricity customers in this Commonwealth from obtaining the benefits of a
5 properly functioning and workable competitive retail electricity market.”

6 Similarly, Section 2210(a) of the Public Utility Code (66 Pa. C.S. § 2210 (a))
7 provides that the Commission shall consider whether a proposed merger or
8 consolidation involving natural gas distribution companies or natural gas
9 suppliers “is likely to result in anticompetitive or discriminatory conduct,
10 including the unlawful exercise of market power, which will prevent retail gas
11 customers from obtaining the benefits of a properly functioning and effectively
12 competitive retail natural gas market.”

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

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

18 The analysis that I conducted accords with the FERC’s Competitive Analysis
19 Screen as described in Appendix A to the Merger Policy Statement, as further
20 modified in Order No. 642 and the revised filing instructions in Section 33 of
21 FERC’s Regulations. The FERC analysis is intended to comport with the
22 Department of Justice and Federal Trade Commission Horizontal Merger
23 Guidelines. The primary focus of my analysis is on potential horizontal market

1 power effects (e.g., for the electric business, those arising from the combination of
2 electric generating assets). I also address vertical effects concerning barriers to
3 entry that might interfere with the long-run competitiveness of the wholesale
4 market for electricity.

5 **Q. Please describe the results of your analysis.**

6 A. As described in my testimony to FERC, the merger of two large generators in the
7 Eastern portion of PJM would, absent mitigation, raise serious market power
8 issues. However, the Joint Petitioners propose to mitigate these potential effects
9 by divesting control of 5,500 MW of generation, of which at least 5,300 MW is in
10 the PJM East market.¹ The divestiture is in the form of 1) virtual divestiture of
11 the equivalent of 2,600 MW of nuclear generation, and 2) outright divestiture of
12 2,900 MW of intermediate and peaking fossil generation. The divestiture of fossil
13 generation will be to no less than two parties, neither of whom can have a
14 significant share of generation ownership in PJM East or Expanded PJM. The
15 nuclear divestiture will be a combination of a long-term (at least 15 year) sale of
16 output to a third party and/or an auction of firm 7X24 nuclear energy into PJM
17 East on a rolling three-year basis. The auction will be in 25 MW blocks; this is
18 intended to facilitate competition to serve retail load. As with the fossil auction,
19 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.

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

8 **Q. What geographic markets did your analysis cover?**

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

20 **Q. What products did your analysis cover?**

21 A. FERC's analysis focuses primarily on electric energy. Two measures of a
22 supplier's size are considered: Economic Capacity and Available Economic
23 Capacity. The former is the whole of generation controlled by a supplier and the

1 latter measures the supplier's share of the market after netting off the generation
2 that is used to meet affiliated retail and requirements load. FERC considers
3 Economic Capacity the more important of the two. This is particularly true in an
4 area, such as PJM East, where there is full retail access and where, indeed, it is
5 not possible to even know from available data which and how much generation is
6 committed to retail customers on a long-term basis.

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

10 **Q. What is the Reliability Pricing Model?**

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

19 **Q. How is the energy market analysis conducted?**

20 A. Consistent with the Merger Guidelines, the analysis focuses on market structure.
21 The specific metric used is the Herfindahl-Hirschman index (HHI). To compute
22 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.

1 less than 1000 (post merger), the equivalent of a market with ten equal-sized
2 participants, any merger passes. If the sum is between 1000 and 1800, the screen
3 is passed so long as the increase in the HHI is 100 points or less. Examples of a
4 100 point increase would be a firm with a 5 percent share merging with a firm
5 with a 10 percent share, or a firm with a 2 percent share merging with a firm with
6 a 25 percent share. Finally, if the HHI is above 1800, an increase of 50 points
7 passes the screen and an increase between 50 and 100 points may or may not,
8 depending on the circumstances.

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

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

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

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

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

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

18 FERC has concluded that both the upstream (pipeline) market and the
19 downstream (electricity) market need to be highly concentrated (HHI greater than
20 1800) in order to raise vertical concerns. In examining downstream markets,
21 FERC requires that gas-fired generation be attributed to the supplier (LDC or
22 pipeline) to whom it is connected. In examining upstream markets, shares of gas
23 transmission capacity are allocated to the holder of firm transportation rights. I

1 examined the post-merger, post-mitigation upstream and downstream markets.
2 There are screen failures in the downstream market. Because of a peculiarity of
3 the required screen, the proposed divestiture of generation that cures screen
4 failures in the electricity analysis does not cure these failures, despite that the
5 downstream market is the electricity market. This is because divested gas-fired
6 generation still is allocated to Exelon/PSEG for vertical analysis purposes since it
7 still is connected to their distribution systems. However, the upstream market is
8 not highly concentrated, so the conditions that FERC deems necessary for
9 creating a vertical market power problem are absent.

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

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

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

17 A. Any effect will be beneficial. The primary effect anticipated from the merger will
18 be that the capacity factors for the PSEG-operated nuclear plants will increase.
19 Increasing nuclear output will have a small but significant tendency to lower
20 wholesale prices. This is because increasing the amount of energy at “the bottom
21 of the stack” will in at least some hours lower the PJM marginal cost. This should
22 lower LMP prices, particularly in PJM East. Lower LMPs will mean a reduced

1 wholesale component of retail rates for all Pennsylvania customers being served
2 out of the competitive wholesale market.

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

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

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

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

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

18 A. No. Neither company controls significant wellhead supplies or long distance,
19 interstate pipelines. Both individually and collectively, they do not have a
20 dominant share of pipeline capacity. Each company operates a gas distribution
21 business. However, their franchise areas are separate and distinct, with PSE&G's
22 in New Jersey and PECO's in Pennsylvania. PECO's franchise natural gas
23 operations are fully regulated by this Commission. PSEG is withdrawing from

1 the competitive retail gas business and serves no customers in Pennsylvania.
2 Exelon is a minor supplier (other than to customers in its franchise area), serving
3 only a few gas customers in Western Pennsylvania.

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

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

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

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

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

1 A. Yes, it does.

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

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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1 I. PURPOSE, SUMMARY OF ANALYSIS AND CONCLUSIONS

2 **Introduction**

3 **Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

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

6 **Q. PLEASE SUMMARIZE YOUR RELEVANT PROFESSIONAL BACKGROUND.**

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

20 **Purpose**

21 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

22 A. I have been asked by Exelon Corporation (“Exelon”) and all its jurisdictional public
23 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”).

1 jurisdictional public utilities² (collectively, the “Applicants”) to evaluate the potential
2 competitive impact of the merger of Exelon and PSEG (creating Exelon Electric & Gas,
3 or “EEG”) on relevant electricity markets.³ I performed the Competitive Analysis Screen
4 described in Appendix A to the Commission’s Merger Policy Statement (“Order No.
5 592”),⁴ as modified in the Revised Filing Requirements Under Part 33 of the
6 Commission’s Regulations.⁵ The Competitive Analysis Screen is intended to comport
7 with the Department of Justice and Federal Trade Commission (“DOJ/FTC”) Horizontal
8 Merger Guidelines (“Guidelines”). I also have analyzed other electricity-related product
9 markets (e.g., ancillary services and capacity). I further provide analyses to show that the
10 proposed mitigation cures all screen failures in all relevant markets.

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

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”).

1 **Summary of Analysis and Conclusions**

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

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

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

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 to 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.

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

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

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

1 ComEd also continues to have provider of last resort ("POLR") responsibilities that
2 continue at least to the end of 2006.¹⁰ ComEd secures generation supply to serve its
3 POLR responsibilities through a full-requirements contract with Exelon Generation.
4 ComEd's three wholesale (full or partial) requirements customers are served under fixed-
5 price contracts that run through 2007, and its retail customers have frozen bundled rates
6 through 2006. Exelon Generation has about 15,000 MW of owned generation and
7 purchase contracts to serve ComEd's expected approximately 18,000 MW of load in
8 2006. Thus, at least through 2006, Exelon has virtually no "excess" generation in respect
9 of its ComEd load requirements.

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

13 PSEG Power's load and contractual commitments. PSE&G procures resources to serve
14 its load via the New Jersey Basic Generation Service ("BGS") auctions. Contracts have
15 been secured to serve load in rolling three-year tranches, some of which extend into 2007.
16 Affiliates of PSE&G participate as suppliers in the BGS auction, and are responsible for
17 the supply of approximately 4,200 MW for the period June 2005 to June 2006 and 1,700
18 MW for the period June 2006 to June 2007, either directly as a winner in the BGS auction
19 or indirectly as a supplier to other winners in the BGS auction. Additionally, PSE&G
20 affiliates are serving 275 MW of Duquesne POLR load through May 2006 and have sold
21 500 MW of firm energy to FirstEnergy through 2008. Given PSEG Power's
22 approximately 12,000 MW of generation in the Mid-Atlantic portion of PJM (prior to
23 merger-related divestitures), these commitments reduce its uncommitted capacity to
24 about 7,000 to 10,000 MW in 2006. Moreover, it is likely that PSEG will secure further
25 commitments during the 2005 New Jersey BGS auction. Indeed, PSEG's publicly-stated

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.

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

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

11 **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.

12
13 There are two key elements of Applicants' mitigation plan: (1) divestiture of substantial
14 coal, mid-merit and peaking capacity, and (2) virtual divestiture of nuclear baseload units
15 through a combination of a) long term energy sales contracts or swaps with parties that
16 do not have significant generating assets in PJM and b) an auction of rolling three-year
17 firm contracts. To the extent nuclear baseload capacity in PJM East is divested or
18 decommissioned the virtual divestiture requirement will be reduced equivalently.
19 Applicants also have committed to mitigation measures in the PJM capacity markets.

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.

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

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

19 Under the Long-Term Contract, Applicants will sell 15-year or longer entitlements to
20 PJM East baseload energy (or swap PJM East baseload energy for baseload energy in a
21 non-PJM market). Two alternative products will be available under this option. The first
22 mirrors the Baseload Auction (*i.e.*, it is a firm 7X24 product), except that the term is for a
23 minimum of 15 years following the close of the merger. The alternate product replaces
24 the firm 24X7 must-take energy product delivered at the aggregate of Applicants' PJM
25 East nuclear generation buses with a guarantee of delivery based on the performance
26 characteristics of a designated PJM East nuclear facility. Applicants will guarantee
27 delivery of an annual amount of energy based on the designated facility's historical
28 capacity factor, and the contract will be for the lesser of the term of the contract (*e.g.*, 15
29 years) or the date that the unit is decommissioned. Any permanent plant deratings will be
30 reflected in the contract terms. This alternate product will facilitate an energy swap

1 agreement, if Applicants choose that option. The amount of a contract with any single
2 party will be no more than one-half of the virtual divestiture amount. Additionally,
3 suppliers with a market share of 5 percent or more of capacity in either PJM East or
4 Expanded PJM will not be eligible for such bilateral contracts, nor will suppliers with
5 market shares between 3 and 5 percent be permitted to purchase, in aggregate, more than
6 25 percent of the capacity to be divested or sold under long-term contract.

7 Mitigation will continue subject to the condition that the virtual divestiture requirement
8 will be extinguished, megawatt for megawatt, to the extent that Applicants' PJM East
9 nuclear capacity is decommissioned, derated or sold, and to the extent that new
10 transmission capacity is constructed into PJM East that is not reflected in PJM's
11 transmission expansion plan in the PJM Regional Transmission Report that is in effect as
12 of June 2005.¹²

13 The virtual divestiture will eliminate any Competitive Analysis Screen failures during
14 off-peak periods¹³ and will eliminate any increased incentives that the merged company
15 theoretically would have to economically or physically withhold non-nuclear generation
16 arising from retained ownership of the nuclear facilities underlying the virtual divestiture.

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

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.

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

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

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

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

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

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

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

Period	Price	Pre-Merger						Post-Merger				Mitigation and Post-Mitigation Results					
		Exelon		PSEG		Mkt Size	HHI	EEG			Mitigation MW	Nuclear	Mkt Share	HHI	HHI Chg	MW Summer	
MW	Share	MW	Share	MW	Share			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	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

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

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

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

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

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.

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

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

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

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.

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

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

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

15 That there will be no competitive harm in wholesale markets is also important from a
16 retail perspective. Competitive retail markets rely on procurement of power from a
17 competitive wholesale market, and, thus it is important from an ultimate customer
18 perspective that the merger not increase market power in wholesale markets. Further,
19 while not directly relevant to the Commission's approval of this transaction, it is notable
20 that the merger also will not eliminate any competitor in retail markets. Only Exelon has
21 a retail marketing affiliate, and it is not active in PJM East. PSEG has no retail marketing
22 affiliates and, thus, no retail supplier is eliminated as a result of the merger.

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

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.

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

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

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

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

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

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.

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

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

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

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

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.

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

4 **Q. PLEASE DESCRIBE EXELON'S ENERGY DELIVERY BUSINESS.**

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

11 Neither PECO nor ComEd owns generation, and each serves its customers' capacity and
12 energy needs through PPAs with Exelon Generation. PECO currently has no
13 requirements customers. ComEd has three partial or full requirements wholesale
14 customers within its control area served under fixed price contracts through May 31,
15 2007: the cities of Naperville (full requirements), Batavia and St. Charles.²⁹

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

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.

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

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

13 **Q. PLEASE DESCRIBE EXELON’S RETAIL COMPETITIVE ENERGY SUPPLY**
14 **BUSINESS.**

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

20 **PSEG, PSE&G and PSEG Power**

21 **Q. PLEASE DESCRIBE PSEG.**

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

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.

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

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

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

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

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

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.

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

3 **Q. PLEASE DESCRIBE PSEG POWER.**

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

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

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.

1 supply the products produced by the merging parties and whose ability to do so
2 diminishes the ability of the merging parties to increase prices. Hence, determining the
3 scope of a market is fundamentally an analysis of the potential for competitors to respond
4 to an attempted price increase. Typically, markets are defined in two dimensions:
5 geographic and product. Thus, the relevant market is composed of companies that can
6 supply a given product (or its close substitute) to customers in a given geographic area.

7 **Horizontal Market Power Issues**

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

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

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”).

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

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

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

14 **Q. WHAT PRODUCTS HAS THE COMMISSION GENERALLY CONSIDERED?**

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

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.

1 Capacity and Available Economic Capacity³⁹ are used as measures of energy. The
2 Commission's current policy does not specify required analyses of capacity markets as
3 such, likely because competitive conditions in the energy market in peak periods closely
4 correlate with conditions in capacity markets. Nevertheless, I have analyzed the PJM
5 Unforced Capacity Credit ("UCAP") market.

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

14 Order No. 642 directs Applicants to analyze relevant ancillary services markets
15 (specifically, reserves and imbalance energy⁴⁰) "when the necessary data are available."
16 As discussed below, I analyzed relevant ancillary services markets within the limits of the
17 quantitative data available.

18 **Q. HOW HAS THE COMMISSION ANALYZED GEOGRAPHIC MARKETS?**

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

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.

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

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

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

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

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.

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

5 **Vertical Market Power Issues**

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

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

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

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

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

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

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

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

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

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").

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

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

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

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

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.

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

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

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.*

1 **IV. DESCRIPTION OF METHODOLOGY**

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

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

10 **Q. WHAT DESTINATION MARKETS DID YOU CONSIDER?**

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

17 **Table 3: Applicants' Generation in PJM**

	<u>Exelon</u>	<u>PSEG</u>
	(MW)	(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	<u>26,341</u>	<u>13,963</u>

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.

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

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

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

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.

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

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

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

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

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

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

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

7 **Table 4: Applicants' Generation Outside of PJM**

		<u>Exelon</u>	<u>PSEG</u>
NERC	RTO	(MW)	(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		<u>6,714</u>	<u>4,197</u>

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

8
 9 **Q. WHAT TIME PERIODS DID YOU ANALYZE?**

10 A. For each relevant market, I examined ten time periods for both the Economic Capacity
 11 and Available Economic Capacity measures, selected to reflect a broad range of system
 12 conditions. Broadly, I evaluated hourly load data to aggregate similar hours. I defined
 13 periods within three seasons (Summer, Winter and Shoulder) to reflect the differences in
 14 unit availability, load and transmission capacity. Hours were first separated into seasons
 15 to reflect differences in generating availability and then further differentiated by load
 16 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

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

3 **SUMMER** (June-July-August)

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

8 **WINTER** (December-January-February)

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

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

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

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

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

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.

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

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

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

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

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.

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

5 **Q. HOW DID YOU ALLOCATE LIMITED TRANSMISSION CAPACITY?**

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

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

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.”

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

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

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

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

26 **A.** Analyzing each of the relevant PJM markets requires an assumption about simultaneous
27 import limit ("SIL"). As shown in Exhibit J-6, for imports into PJM East, I assumed a
28 SIL of 7,300 MW, based on a study conducted by PSEG's transmission engineering

1 group.⁶⁰ When I analyzed the PJM East market, I assumed that generation in the rest of
2 PJM Pre-2004 competed for the limited transmission. In other words, I did not “squeeze”
3 generation from Far West to West to Central. This is consistent with the assumption that,
4 although PJM East is a sometimes-constrained market, the remaining interfaces in PJM
5 Pre-2004 are not often constrained or constrained at the same time as PJM East.

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

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

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>

1 Q. WHAT YEAR DID YOUR ANALYSIS COVER?

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

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

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

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

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). 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. 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

1 Revised Filing Requirements and in subsequent orders concerning market rate authority,
2 the Commission has emphasized the first of these criteria.⁶⁵ For most purchases and
3 sales, I am unable to determine whether the seller or buyer has control⁶⁶ and in those
4 cases I assigned control to the buyer. I note, however, that the treatment of purchases and
5 sales is inconsequential in terms of the results of my analysis, except with respect to
6 Applicants' contracts.

7 Exelon Generation has several long-term (more than one-year) contracts of relevance for
8 the output of various plants located in the former ComEd control area. Through mid-
9 2011, Exelon Generation has contracts with affiliates of Dominion to purchase the output
10 of two coal-fired plants (Kincaid and State Line) formerly owned by ComEd. In my
11 analysis, I treated the entire output of these units as available to (and controlled by)
12 Exelon Generation when economic. Exelon Generation also has a series of long-term
13 PPAs for approximately 3,600 MW of supply from merchant generation, mostly peakers,
14 located in the former ComEd control area.⁶⁷ Again, in my analysis, I treated these PPAs
15 as if Exelon Generation controls the units.

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.

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

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

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

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

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

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

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.

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

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

10 **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
<i>Economic Capacity</i>	7,180	3,822	11,002	15,340
Exelon Generation Owned and Contracted-For Resources				
Peak Load, 2006	8,033	0	8,033	18,000
<i>Available Economic Capacity</i>	NA	NA	2,969	(2,660)

11
12 Table 6 below reflects Exelon's net position in the ICAP market in 2006. However, the
13 ICAP analysis I undertake later is based on Exelon's gross, rather than net, ICAP
14 position.

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
<i>Economic Capacity</i> 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
<i>Available Economic Capacity, Jun '05-May '06</i>			7,042	1,946
Load Commitments, Jun '06-May '07			2,200	
<i>Available Economic Capacity, Jun '06-May '07</i>			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

1 delivery requirement following the shape of the 100 MW of peak load. The peak load
 2 could be slightly higher or lower depending on customer migration and load growth.
 3 PSEG also has a commitment to serve 275 MW of Duquesne POLR obligations
 4 (capacity, energy and ancillary services) through May 2006, and a commitment to
 5 provide 500 MW of firm energy to FirstEnergy for delivery at PJM West through 2008.
 6 For purposes of analyzing Available Economic Capacity, I reflect PSEG's commitment
 7 to serve 4,975 MW of load through May 2006 (4,200 MW BGS, plus 275 MW
 8 Duquesne, plus 500 MW FirstEnergy) and 2,200 MW of load for the remainder of 2006
 9 (1,700 MW BGS plus 500 MW FirstEnergy), as shown in Table 7 above.⁷⁰

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

12 **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

13
14
⁷⁰ PSEG also has commitments to provide approximately 150 MW to retail aggregators. I conservatively did not include this in my analysis.

1 V. IMPACT OF THE MERGER ON COMPETITION

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

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

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

15 **PJM Markets: Economic Capacity**

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

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

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

Period	Price	Pre-Merger						Post-Merger			
		Exelon		PSEG		Mkt Size	HHI	EEG			
		MW	Mkt Share	MW	Mkt Share			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

Period	Price	Pre-Merger						Post-Merger			
		Exelon		PSEG		Mkt Size	HHI	EEG			
		MW	Mkt Share	MW	Mkt Share			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

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

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

11 Table 11: Economic Capacity, Expanded PJM

Period	Price	Pre-Merger						Post-Merger			
		Exelon		PSEG		Mkt Size	HHI	EEG			
		MW	Mkt Share	MW	Mkt Share			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

12
13 **PJM Markets: Available Economic Capacity**

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

16 A. Yes, although I note that developing a comprehensive Available Economic Capacity
17 analysis is quite difficult, given the status of retail access in PJM. Under conditions of
18 full retail access, the Available Economic Capacity analysis becomes identical to
19 Economic Capacity. However, despite full retail access in some portions of PJM (e.g.,
20 Pennsylvania, New Jersey and Illinois), both Exelon and PSEG have continuing load
21 obligations: PECO in the form of a requirement to provide POLR service to its

1 customers through 2010 and PSEG in the form of load commitments secured as a
2 participant in the New Jersey BGS auction. Thus, my analysis of Available Economic
3 Capacity takes into consideration Applicants' commitments to serve customer loads. As
4 described earlier, PECO's peak load commitments are forecast to be approximately 8,000
5 MW and PSEG's peak load commitments conservatively are assumed to conservatively
6 be 2,200 MW.⁷² ComEd also is assumed to have load consistent with its POLR
7 commitments totaling approximately 18,000 MW.

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

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).

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

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

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

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

3 A. Exhibit J-8 presents a series of results for Available Economic Capacity. For PJM East,
4 as shown on page 1, Exelon's Available Economic Capacity ranges from about 800 MW
5 to about 2,400 MW, depending on the time period considered, and PSEG's ranges from
6 about 400 MW to about 8,300 MW. Assuming no other generation in PJM East is
7 committed to serving load, their combined shares of Available Economic Capacity range
8 from 12 to 32 percent. The market is unconcentrated or moderately concentrated and the
9 HHI changes are as high as about 400 points. However, after consideration of
10 Applicants' mitigation plan, Applicants' market share is reduced to no more than about
11 17 percent and, in all instances, the transaction is deconcentrating.

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

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

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

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

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

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

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

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

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

20 **Other Relevant Markets**

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

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

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:

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

4 Table 4: Applicants' Generation Outside of PJM

		Exelon	PSEG
NERC	RTO	(MW)	(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.

5 *ISO-NE*. Exelon's 630 MW of affiliated generation in ISO-NE includes New Boston and
6 West Medway located within the Northeastern Massachusetts ("NEMA") load pocket and
7 a few megawatts of generation located in Maine. PSEG's 967 MW of affiliated
8 generation in ISO-NE includes Bridgeport Harbor and New Haven Harbor located in
9 Southwest Connecticut and a few megawatts of generation located in New Hampshire.
10 Thus, the smallest relevant market in which both Applicants' generation would compete
11 is ISO-NE as a whole. Relative to ISO-NE's total generation (in excess of 30,000 MW),
12 Exelon's affiliated generation is only 2 percent and PSEG's affiliated generation is only 3
13 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.

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

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

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

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.

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

4 **Capacity Markets in PJM**

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

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

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

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

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>

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

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

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

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

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.

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

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

16 Q. WHAT DOES YOUR ANALYSIS SHOW FOR PJM EAST?

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

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.

1 Q. PLEASE DESCRIBE THE SPINNING RESERVE MARKET.

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

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

16 In the PJM Mid-Atlantic in 2001 (no similar more recent data are available), there was a
17 maximum capability of 3,033 MW of spinning reserves relative to maximum requirements
18 of 2,271 MW.⁸⁶ Actual requirements ranged as high as 2,513 MW between 1999 and
19 2003. Lacking any other data, I have used these data in my analysis.

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

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

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.

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

5 **Table 14: Spinning Reserves Market, Mid-Atlantic**

	<u>(MW)</u>	<u>Share</u>
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

6
7 **Q. PLEASE DESCRIBE THE REGULATION MARKET.**

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

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

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

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

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

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

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

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.

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

3 **Table 15: Regulation Market, PJM Mid-Atlantic**

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

4
5 It also should be noted that the separate analysis of ancillary services, including both spin
6 and regulation, is subject to the caveat that they cannot cleanly be analyzed separately
7 from energy and each other. PJM co-optimizes energy and ancillary services. A given
8 MW of capacity cannot be used to provide more than one service at any point in time.
9 Moreover, because the energy price is a major element in pricing both regulation and
10 spinning reserves, prices for the two products are intrinsically linked. Indeed, it is prices
11 in the energy market that primarily determine the cost of procuring regulation and Tier 1
12 spin.

13 **Mitigation**

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

16 A. The amount of mitigation required to eliminate screen failures in the Competitive
17 Analysis Screen is largely a mathematical exercise: determining the post-merger market
18 share for Applicants that yields HHI changes within the screen threshold, and then
19 translating the reduction in Applicants' market share into the required megawatts of
20 divestiture. This is done for each of the time periods/price levels analyzed. Since
21 Economic Capacity is an analysis of energy, the megawatts to be divested need to be
22 adjusted for assumed outages to determine the equivalent capacity to be divested. This
23 requires a determination of typical, or average, outages by season and by type of
24 generation within the relevant categories of coal, mid-merit and peaking capacity. Based
25 on this analysis, I determined the amount of divestiture required for each of the categories
26 of units to be divested. A specific divestiture outcome that solves screen failures in all

1 time periods will, in fact, reduce the HHI change to below target levels in other time
2 periods.⁹⁰ For example, a divestiture that eliminates a screen failure in the Summer SP2
3 period, with a price of \$80/MWh, will over-mitigate the Winter SP period, which also has
4 a price of \$80/MWh.

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

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

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

Period	Price	Pre-Merger						Post-Merger				Mitigation and Post-Mitigation Results					
		Exelon		PSEG		Mkt Size	HHI	EEG			Mitigation MW	Nuclear	Mkt Share	HHI Chg	MW Summer		
MW	Share	MW	Share	MW	Share			MW	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	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	83	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

Period	Price	Pre-Merger						Post-Merger				Mitigation and Post-Mitigation Results					
		Exelon		PSEG		Mkt Size	HHI	EEG			Mitigation MW	Nuclear	Mkt Share	HHI Chg	MW Summer		
MW	Share	MW	Share	MW	Share			MW	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	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

Period	Price	Pre-Merger				Post-Merger				Mitigation and Post-Mitigation Results							
		Exelon		PSEG		EEG				Mitigation	Nuclear		Mkt	HHI	HHI	MW	
		MW	Share	MW	Share	Mkt Size	HHI	MW	Share	HHI	Chg	MW		Share	HHI	Chg	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

3 Vertical Market Power

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

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

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

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

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

16 A. As described earlier, PECO's LDC operations serve a limited area in eastern
17 Pennsylvania. PECO offers transportation services to all of its customers, and a large
18 number of customers obtain their gas commodity from third-party suppliers. PECO's
19 LDC system is easily bypassed by large customers. While PECO Energy is permitted to
20 discount its transportation rate to meet competitive pressures, there are a number of
21 customers on PECO's system who have opted to bypass the utility completely and

1 connect directly to an interstate gas pipeline (e.g., Sun Oil and Tosco have done so).
2 Existing larger customers have used the threat of bypass to achieve reduced rates. As
3 noted earlier, PECO provides gas distribution service to only three unaffiliated electric
4 generators totaling less than 200 MW. These are either industrial facilities that consume
5 the bulk of their electricity on-site or facilities that use natural gas as a secondary fuel.
6 Other independent generators located in their service area take service directly from the
7 pipeline. Newly built facilities could readily avoid PECO's small service area or connect
8 directly to an interstate pipeline.

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

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

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

19 A. The three largest interstate pipelines serving Pennsylvania and New Jersey are Tennessee
20 Gas Pipeline, Texas Eastern Transmission and Transcontinental Gas Pipe Line. These
21 pipelines represent about 90 percent of capacity entering New Jersey and about 70
22 percent of capacity entering Pennsylvania. Columbia Gas Transmission and Dominion
23 Transmission are the other two significant pipelines serving Pennsylvania (12 percent and
24 10 percent of entering capacity, respectively).⁹¹ I examined Applicants' firm transmission
25 reservations on each of these pipelines (excluding those expiring prior to 2006 with no
26 rollover rights). Exelon's total firm transmission reservations total about 500 mmcf/day,

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

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

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

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

24 A. I completed the downstream portion of the required analysis under Section 33.4 of the
25 Commission's regulations. That framework requires that the structure of downstream
26 markets be analyzed using the same delivered price test methodology as in the horizontal
27 market power analysis, but with gas-fired generation deemed to be controlled by (*i.e.*, is
28 assigned to) its gas supplier rather than its owner. I attributed gas-fired generation to the
29 upstream suppliers, *i.e.*, the pipeline that serves it. For power plants directly connected to

1 a single pipeline, the entire capacity of the plant is attributed to the pipeline. If the
2 pipeline is jointly owned, the capacity is divided among the pipeline owners. For power
3 plants directly connected to multiple pipelines, the plant's capacity is divided into equal
4 shares and attributed to the pipelines that are connected. If a pipeline connection cannot
5 be determined, or the plant is served by an LDC (other than Applicants' LDC) that is fed
6 by multiple pipelines, the capacity is assigned to the actual owner of the unit. For plants
7 served by PECO or PSE&G, as well as for gas-fired plants owned by Applicants, I
8 assigned the capacity to Applicants. These are detailed in Table 18 below.

9 **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

10
11 I analyzed the downstream market for PJM East, PJM Pre-2004 and Expanded PJM.
12 After taking into account Applicants' mitigation commitments, neither the PJM Pre-2004
13 nor the Expanded PJM markets are highly concentrated post-merger, as shown in Exhibit
14 J-15. However, the PJM East market remains highly concentrated post-mitigation. In
15 performing this analysis, I only counted the divestiture of nuclear or coal units; if some of
16 the divested units are oil-fired, they too would represent a reduction in Applicants'
17 market share and would likely reduce concentration below 1800. Nevertheless, since the
18 PJM East downstream market is highly concentrated, consistent with the Commission's
19 regulations, I conducted an analysis of the PJM East upstream market. The analysis of
20 the upstream market requires that the structure of control of transportation capacity be
21 examined. For this purpose, I allocated control of gas transportation pipelines to holders

1 of firm capacity rights, with any unsubscribed capacity allocated to the pipeline owner.
2 Details of this approach are provided below and in Exhibit No. J-4.

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

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

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

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

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

22 A. No. I was unable to identify any special barriers to entry in this regard. The service areas
23 of these Applicants are relatively small, and the relevant geographic markets in PJM
24 encompass a large region and includes many possible generating sites. Entrants who
25 could compete in areas potentially affected by this merger would not need to locate new
26 facilities in Applicants' service areas or connect to Applicants' transmission systems. In

1 any event, PJM, not Applicants, controls the interconnection process for new generation.
2 Thus Applicants' RTO membership should moot any concerns in this regard.

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

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

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

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

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

⁹³ Merger NOPR, *op. cit.*, at 20.

1 VI. CONCLUSION

2 Q. PLEASE SUMMARIZE YOUR RECOMMENDATION.

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

5 Q. DOES THIS COMPLETE YOUR TESTIMONY?

6 A. Yes.

EXHIBITS

Exhibit J-1	Testimony
Exhibit J-2	Resume of William H. Hieronymus
Exhibit J-3	Applicants' Generation
Exhibit J-4	Data and Methodology
Exhibit J-5	Description of CASm Model
Exhibit J-6	Schematic of Relevant PJM Markets
Exhibit J-7	Economic Capacity
Exhibit J-8	Available Economic Capacity
Exhibit J-9	ICAP
Exhibit J-10	Spinning Reserves
Exhibit J-11	Regulation
Exhibit J-12	Mitigation-Eligible Units
Exhibit J-13	Mitigation Scenarios
Exhibit J-14	Economic Capacity, Post-Mitigation Results
Exhibit J-15	Downstream Economic Capacity
Exhibit J-16	Upstream Market, PJM East

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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),



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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

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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

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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



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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 Muevek 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.

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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



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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.



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- 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	Schuykill	Oil	166	100%		166
MAAC	PJM	Schuykill	Oil	30	100%		30
MAAC	PJM	Schuykill	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			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.

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).

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

⁴ Moreover, this significantly reduces the complexity of modeling the transmission system within MISO, given that MISO now uses flowgates rather than 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

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

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

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

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 NO_x trading programs in the Northeast (OTR).¹⁶ Unit-specific data on NO_x rates (lbs/mmBtu) were taken from the EPA's "2000 Acid Rain Program Emission Scorecard."¹⁷ The NO_x 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

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 NO_x 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 - NO_x 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

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

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

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 merger²⁴ 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.

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.

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.

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.

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 < quantity³, 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:

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 economic⁴ tranches \leq 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) \leq simultaneous limit, for all limits

sum over nodes (net injection * flowgate factor) \leq 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:

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

sum over economic tranches \leq 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.

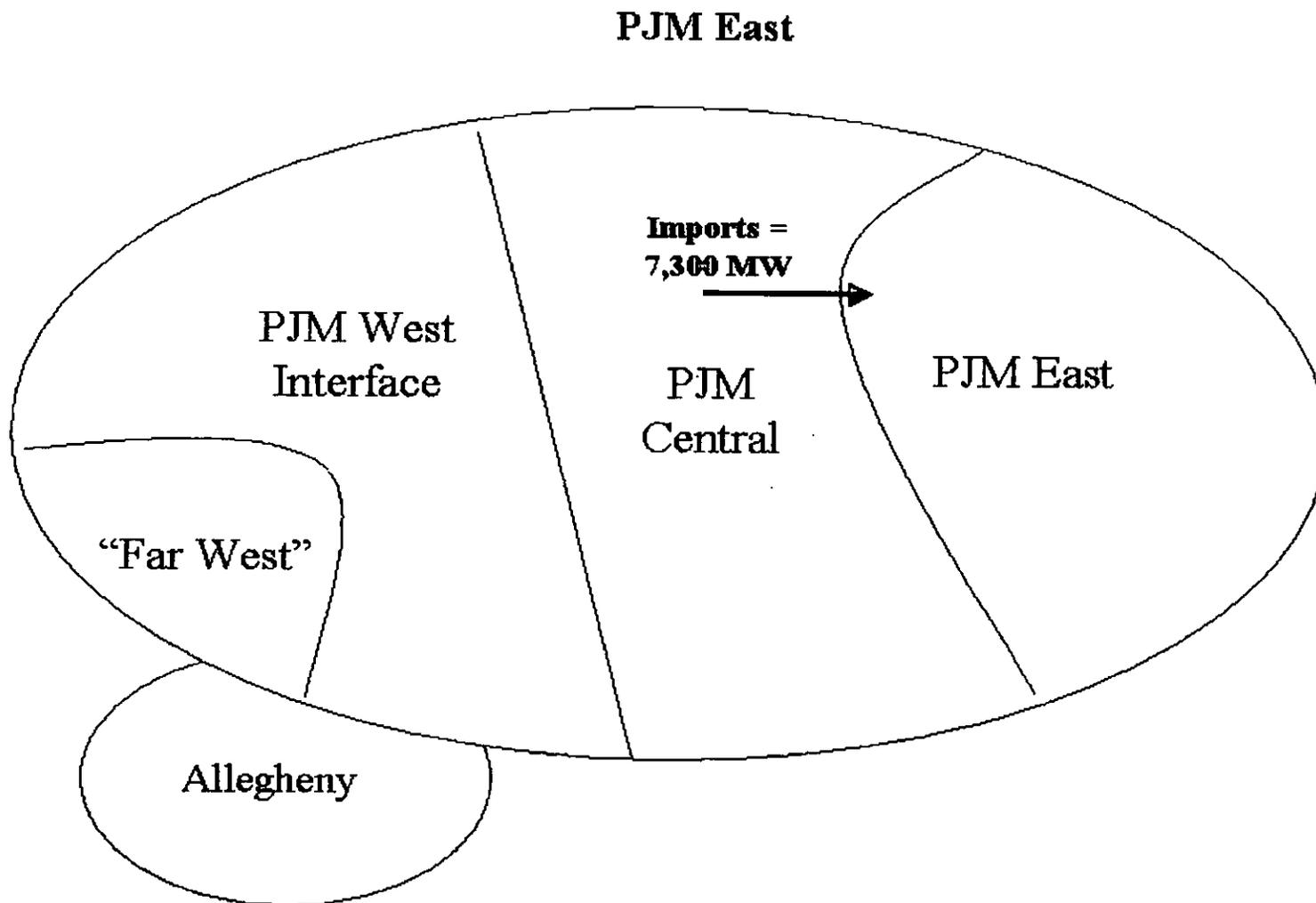
5. If there are simultaneous limits, they are checked for feasibility. All lines that have a worsening effect on a simultaneous constraint, given their defined flow direction, are checked against the simultaneous limit. If they would exceed the simultaneous limit if fully utilized, then their maximum 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

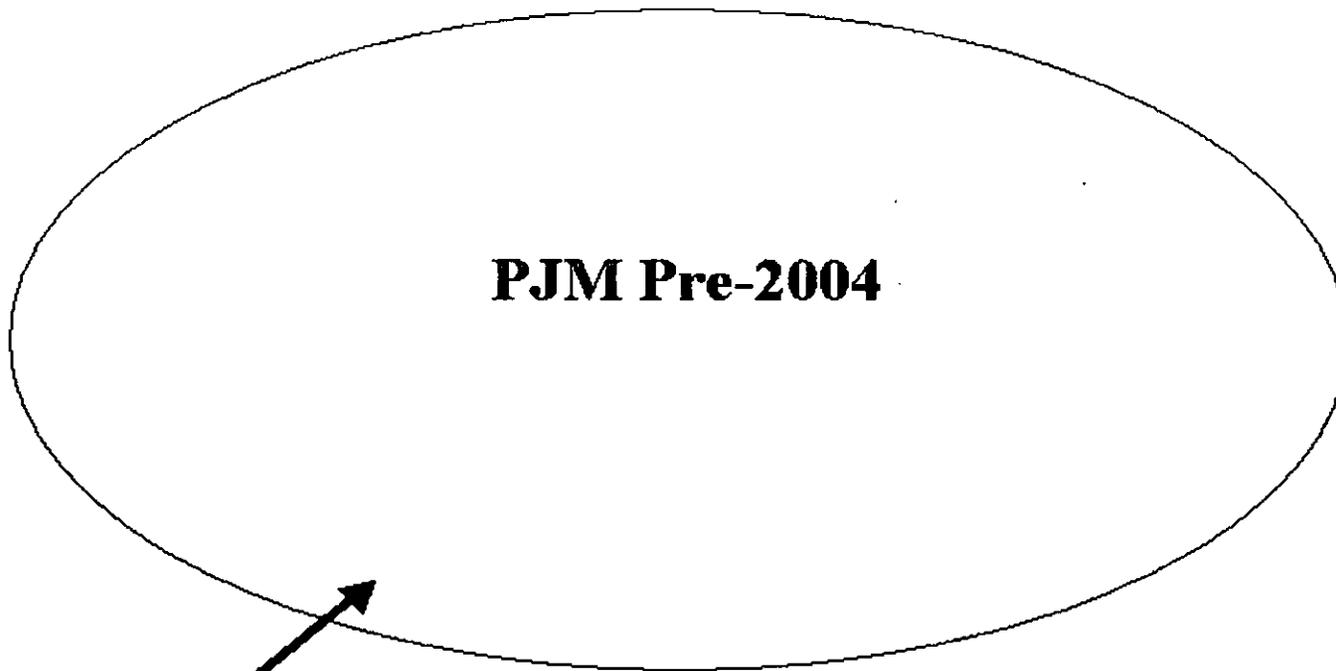
CASm has been implemented using GAMS (Generalized Algebraic Modeling System), release 2.5. GAMS is a programming language which supports both data manipulation and calls to many mainstream mathematical modeling systems. The linear programming problems generated by CASm are solved by BDMLP. The path enumeration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

Schematic of Relevant PJM Markets



Schematic of Relevant PJM Markets

PJM Pre-2004



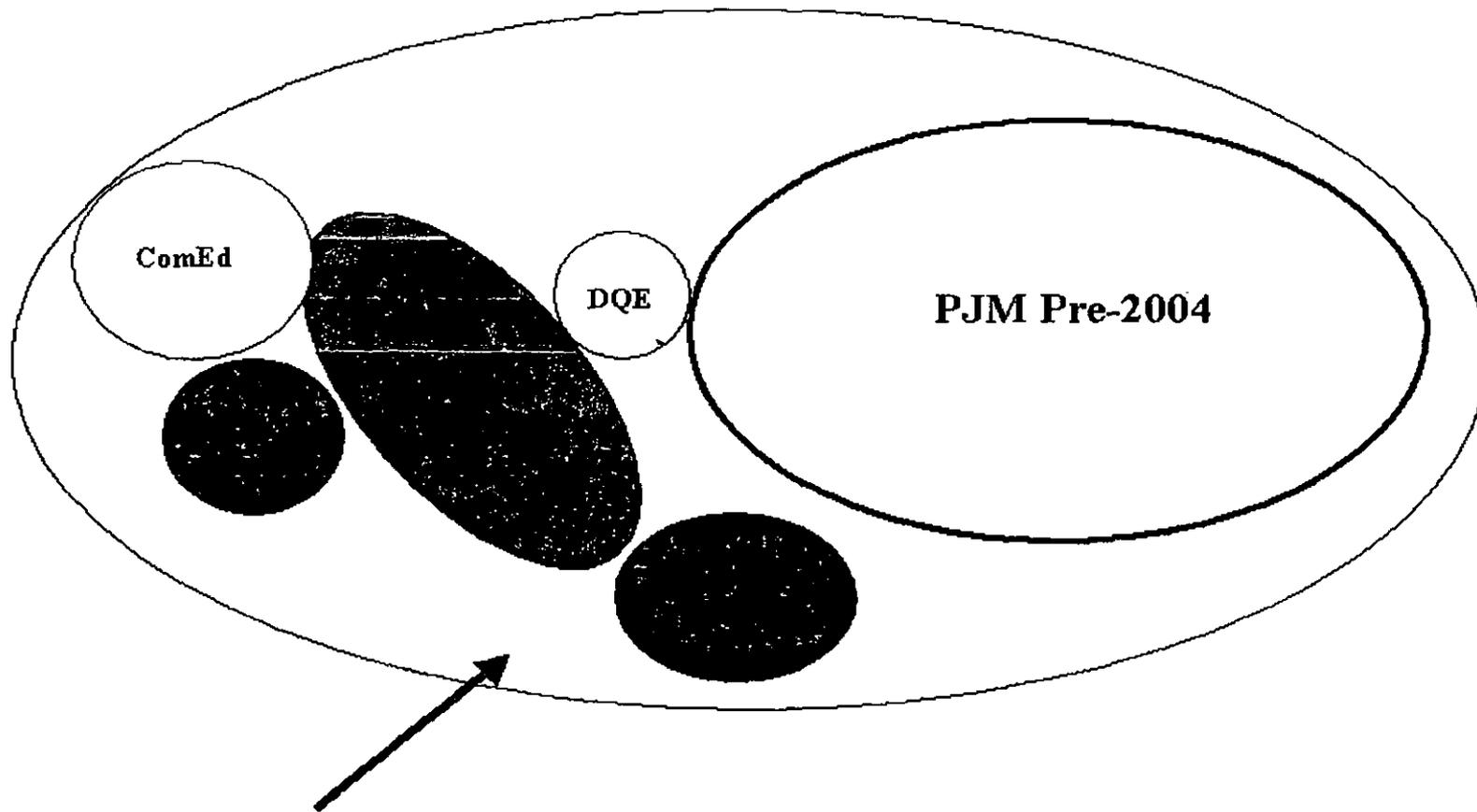
PJM Pre-2004



Simultaneous Import Limit = 4,600 MW

Schematic of Relevant PJM Markets

Expanded PJM



Simultaneous Import Limit = 7,500 MW

Economic Capacity (Pre-mitigation)

Period	Price	Pre-Merger						Post-Merger			
		Exelon		PSEG		Mkt Size	HHI	EEG			HHI Chg
		MW	Mkt Share	MW	Mkt Share			MW	Mkt Share	HHI	
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

Period	Price	Pre-Merger				Post-Merger				Effect of Mitigation				
		Exelon		PSEG		EEG		HHI		Mitig Share	New HHI Chg	Divest		
		MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	MW	Share	HHI	Change			
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

Period	Price	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	
		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

Period	Price	Pre-Merger						Post-Merger				Effect of Mitigation		
		Exelon		PSEG		Mkt Size	HHI	MW	Mkt Share	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

Period	Price	PJM Load	
		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

Period	Price	Pre-Merger						Post-Merger				Effect of Mitigation		
		Exelon		PSEG		Mkt Size	HHI	EEG		HHI Change	Mitig Share	New HHI Chg	Divest	
MW	Mkt Share	MW	Mkt Share	MW	Share			HHI						
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

Period	Price	Pre-Merger		
		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

Period	Price	Pre-Merger						Post-Merger				Effect of Mitigation		
		Exelon		PSEG		Mkt Size	HHI	EEG		HHI Change	Mitig Share	New HHI Chg	Divest	
MW	Mkt Share	MW	Mkt Share	MW	Share			HHI						
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

Period	Price	Pre-Merger				Post-Merger		
		Total PJM Load		Supplied by PJM East Generation		Other Load		
		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.

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.

PJM Spinning Reserve Market (Mid-Atlantic)

	<u>(MW)</u>	<u>Share</u>
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 installed capacity in PJM East and Expanded PJM is no more than 5 percent.

PJM Regulation Market (Mid-Atlantic)

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

Mitigation-Eligible Units

Unit	Type	Summer MW	Winter MW	Summer	Summer	Summer	Summer
				Economic < \$25	Economic Between \$25 and \$55/MWh	Economic Between \$55 and \$80/MWh	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	Winter	Winter
				Economic < \$30	Economic Between \$30 and \$55/MWh	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		Winter		Shoulder	Shoulder	Shoulder
		MW	MW	MW	MW	Economic < \$20	Economic Between \$20 and \$45/MWh	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	Winter	Outages			Derated Capacity			Dispatch Cost (+5%)		
	MW	MW	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.

Economic Capacity (Post-Mitigation Results)

Period	Price	Pre-Merger						Post-Merger				Mitigation and Post-Mitigation Results					
		Exelon		PSEG		Mkt Size	HHI	EEG		HHI Chg	Mitigation MW	Nuclear	Mkt Share	HHI	HHI Chg	MW Summer Equivalent	
		MW	Mkt Share	MW	Mkt Share			MW	Mkt Share								
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)

Period	Price	Pre-Merger						Post-Merger				Mitigation and Post-Mitigation Results					
		Exelon		PSEG		Mkt Size	HHI	EEG		HHI Chg	Mitigation MW	Nuclear	Mkt Share	HHI	HHI Chg	MW Summer Equivalent	
MW	Share	MW	Share	MW	Share			MW	Share								
Scenario 1: Mitigation Required for PJM East																	
<i>PJM Expanded</i>																	
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)

Period	Price	Pre-Merger						Post-Merger				Mitigation and Post-Mitigation Results					
		Exelon		PSEG		Mkt Size	HHI	EEG		HHI Chg	Mitigation MW	Nuclear	Mkt Share	HHI	HHI Chg	MW Summer Equivalent	
MW	Share	MW	Share	MW	Share			MW	Share								HHI
Scenario 2: Total Mitigation (Additional Mitigation Outside of PJM East)																	
<i>PJM Pre-2004</i>																	
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
<i>PJM Expanded</i>																	
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				Mitigation and Post-Mitigation Results						
		EEG		Mkt Size	HHI	Mitigation MW	Nuclear	Mkt		HHI Chg	MW Summer Equivalent	
MW	Share	HHI Chg	Share					HHI				
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				Mitigation and Post-Mitigation Results						
		EEG	Mkt Share	Mkt Size	HHI	HHI Chg	Mitigation MW	Nuclear	Mkt Share	HHI	HHI Chg	MW Summer Equivalent
Scenario 1: Mitigation Required for PJM East												
<i>PJM Expanded</i>												
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	Post-Merger				Mitigation and Post-Mitigation Results						
		EEG		Mkt Size	HHI	Mitigation MW	Nuclear	Mkt Share	HHI	HHI Chg	MW Summer Equivalent	
MW	Share	HHI Chg										
Scenario 2: Total Mitigation (Additional Mitigation Outside of PJM East)												
<i>PJM Pre-2004</i>												
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	
<i>PJM Expanded</i>												
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

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

Source: EIA State Border Capacity (January 2004).

PJM East Delivered Gas Transportation Market

<u>Affiliate Name</u>	<u>Capacity MMcf/D</u>	<u>Market Share</u>	<u>HHI</u>
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).