Met-Ed/Penelec/Penn Power Statement No. 1

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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION



JOINT APPLICATION OF PECO ENERGY COMPANY
AND PUBLIC SERVICE ELECTRIC AND GAS
FOR APPROVAL OF THE MERGER OF
PUBLIC ENTERPRISE GROUP INCORPORATED
WITH AND INTO EXELON CORPORATION

DOCKET NO. A- 110550F0160



TESTIMONY
OF
WILLIAM D. BYRD



Wholesale Market Impacts on Retail Provider of Last Resort Service
Current Retail Provider of Last Resort Service Costs and Competitive Shopping
Recommendations for Market Power Remediation

# TESTIMONY OF WILLIAM D. BYRD

**Q. Please state your name and business address.**

A. My name is William D. Byrd and my business address is FirstEnergy, 76 South Main St., Akron Ohio, 44308.

**Q. Mr. Byrd by whom are you employed and in what capacity?**

A. I am Director, Rate Strategy for the FirstEnergy Service Company. My department has primary responsibility for projecting and assessing future revenue requirements for the regulated utility subsidiaries of FirstEnergy Corp. to develop and evaluate alternative tariff concepts for both state and federal jurisdictions and to assist in the management of specific regulatory filings, including those with the Federal Energy Regulatory Commission ("FERC") and the Pennsylvania Public Utility Commission ("Commission" or "PUC").

**Q. What is your educational and professional background?**

A. I received a B. A. in Economics from Florida Southern College in 1975 and a M.A. in Economics from the University of Chicago in 1977. I joined Ohio Edison in 1977 as a business analyst, holding a variety of staff and supervisory positions in the Economic Studies Department, Rate Department, Advanced Engineering and Planning Department, Market Research Department, Wholesale Marketing Department. Since the formation of FirstEnergy Corp. in 1997, I have held the positions of General Manager – FirstEnergy Trading Services Inc., an unregulated subsidiary engaged in wholesale electricity market;

Director, Enterprise Risk Management Department; and Director, Commodity Supply Planning Department at FirstEnergy Solutions Corp. In this last position I was responsible for acquisition and divestiture of generating assets; negotiation of long-term power transactions; responding to and issuing Request for Proposals for wholesale power; and the provision of analytical support to the commodity operations and trading groups within FirstEnergy Corp. Also, in this position I submitted, on behalf of FirstEnergy Solutions Corp., written and oral comments in the PUC roundtable sessions regarding development of rules for the provision of Provider of Last Resort ("POLR") service.

**Q. On whose behalf are you testifying in this proceeding?**

A. I am testifying on behalf of Metropolitan Edison Company ("Met-Ed"), Pennsylvania Electric Company ("Penelec"), and Pennsylvania Power Company ("Penn Power") (collectively referred to as "the Companies").

**Q. Please describe the purpose of your direct testimony.**

A. The purpose of my testimony, along with the other testimony submitted by the Companies in this proceeding, is to address concerns we have about the effect of the proposed merger on retail electricity consumers in Pennsylvania. Specifically, we have focused on the impact the proposed merger may have on the state's retail electric market, whether the market power mitigation plan submitted by Applicants PECO and PSEG (collectively, the "Applicants") in his proceeding is adequate to mitigate their post-merger market power and other adverse impacts on competitive markets, and additional measures we believe should be required to ensure that retail competition and retail ratepayers in Pennsylvania are not adversely affected.

While the primary focus of my comments will be the potential impact of the proposed PECO-PSE&G merger on the fulfillment of the POLR obligation of Met-Ed and Penelec, Penn Power and its customers will also be affected. Even though Penn Power is in MISO and may be viewed as not currently directly exposed to the PJM wholesale market, it is inevitable that the MISO and PJM markets, over time, will converge. Even if the common market design discussions between MISO and PJM do not achieve this convergence, individual market participants, through their actions will bring the markets together. In simple terms, if there are pricing discrepancies between the two markets, individual participants will arbitrage the differences and bring about convergence.

**Q. Would you please identify any other witnesses submitting direct testimony on behalf of the Companies, and the general subject areas of their testimony?**

A. Yes. Richard A. D'Angelo, in Met-Ed/Penelec/Penn Power Statement No. 2, will present testimony further describing background information pertaining to the Companies' restructuring and resulting dependence on market conditions, and related concerns presented by the proposed merger from a market power perspective. Ms. Julia Frayer, in Met-Ed/Penelec/Penn Power Statement No. 3 and related exhibits, will summarize her independent analysis, conclusions and recommendations related to the market power aspects of the proposed merger as they relate to the Pennsylvania retail market. Ms. Frayer was retained as an independent expert to review the market power

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**Q. Please explain how the Companies currently obtain the power supply for their POLR obligation.**

A. All three Companies currently have in place FERC approved contracts with their affiliate FirstEnergy Solutions Corp. ("FES") for the procurement of their required power supply. For Penn Power, the contract with FES is what is referred to as a "full requirements" contract. FES is obligated to provide whatever quantities of energy, capacity and ancillary services are necessary to meet the requirements of Penn Power's retail and wholesale customers. For Met-Ed and Penelec, each company has a "partial requirements" contract under which FES is obligated to provide whatever amounts of energy and capacity are needed after allowing for the amounts procured directly by the companies. The partial service feature of this contract was required to accommodate the existing, legacy contracts Met-Ed and Penelec have with Non-Utility Generators ("NUGs") under which they procure a fairly constant, but nonetheless variable, amount of energy and capacity.

**Q. When do the contracts with FES expire?**

A. The Penn Power – FES contract expires December 31, 2005. The FES-Met – Ed and the FES – Penelec contracts are both annual "evergreen" contracts which automatically renew, unless terminated with notice by either party, and could be terminated as early as the end of 2005.

**Q. Since the Companies have supply contracts with their affiliate FES, why are they concerned with the potential consequences of this proposed merger?**

A. The Companies do have contracts in place today, but not in the future, and it is the future consequences which are of concern. The Met-Ed and Penelec contracts with FES can be terminated at the end of this year by FES. If this were to occur, these companies will have to directly access the wholesale market place in order to procure the balance of the power supply needed to meet their POLR obligation. As I mentioned above, the Penn Power contract also expires at the end of 2005.

**Q. What will be the consequences to Met-Ed and Penelec if the contracts with FES are terminated?**

A. Both companies will have to access the wholesale market for procurement of the energy, capacity and ancillary services necessary to meet their POLR obligations. And based on recent outcomes of competitive auctions for procurement of POLR supplies conducted in Ohio in December 2004 and in New Jersey in February 2005, the companies can reasonably expect to be confronted with much higher wholesale prices than they are currently paying under the contract with FES.

These circumstances impact Met-Ed and Penelec to a greater degree than Penn Power, because the Penn Power generation rate cap expires at the end of 2006, whereas the Met-Ed/Penelec fixed generation rates are currently scheduled to continue through 2010.

**Q. How much higher would you anticipate these wholesale prices could become?**

A. The auctions in Ohio and New Jersey while valid as indicative pricing points, are not perfect substitutes since wholesale electricity prices are highly dependent on the exact location of the delivery point, the delivery period and the point in time of the auction. Nonetheless, both auction processes were for similar, but not identical, procurement of POLR power supply and given the Ohio clearing price of roughly $54.50 / mwh and the New Jersey clearing price of $65.00 - $67.00 /mwh (there are slight differences for each utility involved in the auction) it is safe to assume that the Companies would be confronted with procurement costs well in excess of the approximately $41.50 /mwh of revenue obtained from retail generation service provided under the existing price caps.

**Q. What does this have to do with the Applicants' proposed merger?**

A. A competitive wholesale market[1] with price transparency and a high degree of liquidity is a necessary condition for a viable, competitive retail market place. Perhaps more importantly, and more subtlety, it is the perception of a competitive wholesale market place which is of concern to the Companies. The Applicants have acknowledged the proposed merger will result in an increase in concentration and increased market power in the energy and capacity markets. To address this, the Applicants proposed a variety of mitigation measures. The Companies' concern is that the mere existence of the *potential*

[1] I am using the phrase "wholesale market" somewhat generically, implicitly referring to numerous, discrete wholesale markets which currently exist in PJM. These discrete markets include markets administered by PJM Interconnection which include the Real Time Hourly Energy Market, the Day Ahead Energy Market, the Daily Capacity Market, the Interval, Monthly and Multi-monthly Capacity Markets, the Regulation Market, the Spinning Reserve Market and the Annual and Monthly Auction Markets in Financial Transmission Rights. In addition to the markets operated by the PJM Interconnection, I use the term to include the existing over-the-counter and bilateral markets where the majority of forward energy and capacity transactions occur.

for the exercise of market power will be detrimental to the Companies, their POLR customers and to the retail market.

**Q. Can you expand on this concern?**

A. Certainly. At some point in the future the Companies will be accessing the wholesale market for procurement of their POLR power supplies, either through bilateral transactions or through more structured procurement processes such as RFPs or auctions as contemplated by the PUC in the proposed POLR rules (Docket No. L-00040169). Potential suppliers to the Companies will seek to be adequately compensated for the risks they *perceive* they will be incurring by entering into supply arrangements with the Companies. Participants which enter into transactions in a marketplace which is structurally characterized by some participants having the potential for the exercise of market power will perceive this as a risk exposure and either incorporate this risk premium into their prices or will require contractual terms which allocate the risks to the Companies. Either way the POLR customers will ultimately pay a higher price than otherwise. For example, look to the Capacity Markets in PJM. In 2001 there was a well publicized exercise of market power in the Daily Capacity Market, which resulted in rule changes within PJM to hopefully preclude a re-occurrence. Even with the rule changes and all of the assurances offered by PJM, term capacity transactions in the PJM market continue to reflect a "rules" premium as all market participants are well aware of the dictum – "Fool me once, shame on you; fool me twice, shame on me." Market power once demonstrated has had a long-term, lingering effect on capacity prices in PJM.

**Q. Are you implying POLR prices will be lower if the proposed merger is not consummated?**

A. Not necessarily, as it depends on the frame of reference. Whether future electricity price levels are higher or lower than historical levels will be determined by a variety of factors including, but not limited to, fuel prices, the institutional structures within which the industry operates, economic growth, environmental rules and laws, transmission investment. Depending on these and other factors, future prices may be higher, lower or the same as historical prices. I am not offering an opinion on the future level of prices. What concerns the Companies is that whatever the level of future prices, the proposed merger will result in prices incrementally higher than they would have been absent the merger, due to the increased concentration of supply and the increased perceptions of the ability for the merged entity to exercise market power.

**Q. Mr. Byrd, do you have any recommendations for the Commission that may mitigate the negative market impact of the proposed merger?**

A. Yes. The Companies retained Julia Frayer, a Managing Director of London Economics International LLC, to conduct a detailed analysis of the economic and market power related aspects of the proposed merger; and, in particular, the mitigation steps recommended by Dr. William Hieronymus on behalf of the Applicants. The results of Dr. Hieronymus' analysis and his related testimony have been submitted both at FERC and in this PUC proceeding on behalf of the Applicants.

As a result of Ms. Frayer's review and analysis, which is being submitted in this proceeding in response to the Heironymus analysis, as Met-Ed/Penelec/Penn Power Statement No. 3, there are several additional mitigation steps that we believe would be appropriate for the Commission to consider. These steps are further described in Ms. Frayer's testimony and exhibits.

**Q. What recommendations would you suggest to the PUC at this point in order to remedy the flaws and concerns identified by your analysis?**

A. The Companies' main concern in these proceedings is that the potential for the exercise of market power will ultimately be to the detriment of retail customers. Since the pending proceedings at FERC may address all or some of the concerns of the Companies, I believe the PUC should await FERC's ruling before rendering any final approval of the proposed merger, and entertain a period for supplemental testimony after FERC's ruling in order to permit parties to address what specific additional measures beyond those that may be ordered by FERC would be appropriate to remedy any remaining retail market power concerns. To the extent that the significant shortcomings identified in Julia Frayer's testimony are addressed in the FERC proceedings, there may not be a need for additional recommendations. However, to the extent retail market power concerns remain, at that point they should be addressed by the PUC. Additional supplemental testimony could be targeted to the specific additional measures that should be imposed by the PUC in order to protect Pennsylvania retail electric generation competition.

**Q. Mr. Byrd, does this complete your direct testimony?**

A. Yes, it does.

Met-Ed/Penelec/Penn Power Statement No. 1-S-1

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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION



JOINT APPLICATION OF PECO ENERGY COMPANY
AND PUBLIC SERVICE ELECTRIC AND GAS
FOR APPROVAL OF THE MERGER OF
PUBLIC ENTERPRISE GROUP INCORPORATED
WITH AND INTO EXELON CORPORATION

DOCKET NO. A- 110550F0160



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PA PUBLIC UTILITY COMMISSION
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SUPPLEMENTAL TESTIMONY
OF
WILLIAM D. BYRD

**Responses to Directed Questions from Commissioner Shane and Vice-Chairman Cawley**

**Surrebuttal to Joint Applicants' Rebuttal Concerning:
Wholesale Market Impacts on Retail Provider of Last Resort Service, Current Retail Provider of Last Resort Service Costs and Competitive Shopping, and Recommendations for Market Power Remediation**

**SUPPLEMENTAL TESTIMONY OF WILLIAM D. BYRD**

**Q. Please state you name and business address.**

A. My name is William D. Byrd. My business address is FirstEnergy, 76 South Main Street, Akron, Ohio 44308.

**Q. Have you previously filed testimony in this proceeding?**

A. Yes. I have filed written direct testimony on behalf of Metropolitan Edison Company ("Met-Ed"), Pennsylvania Electric Company ("Penelec") and Pennsylvania Power Company ("Penn Power"), which has been designated as Met-Ed/Penelec/Penn Power Statement No. 1.

**Q. What is the purpose of this further testimony?**

A. The purpose of this supplemental testimony is to respond to:

a) the written questions (pertaining to electric industry matters) directed to the parties in this proceeding by Commissioner Shane and Vice-Chairman Cawley through a notice from Secretary McNulty dated July 15, 2005; and

b) a limited portion of Applicants' written rebuttal testimony, concerning matters I discussed in my direct testimony.

For purposes of this supplemental testimony, I refer to Met-Ed, Penelec and Penn Power, collectively, as the "FirstEnergy Companies".

## Answers to Directed Questions

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

A. Unfortunately, I believe this merger as proposed, in particular the limited mitigation plan that has been proposed, will impede the development of a robust competitive retail market. Both I and Ms. Julia Frayer, FirstEnergy Companies' independent expert consultant, have outlined the difficulties from the FirstEnergy Companies' perspective with the market power mitigation plan committed to by the Applicants. As I pointed out in my direct testimony, the very existence of the merger, with the size of the utilities involved, will have a chilling effect on competitive electricity pricing.

As capped or frozen rates begin to expire for Pennsylvania retail electricity customers, they will be exposed to the market prices of electricity, which are likely to be significantly higher than Pennsylvania's retail customers were accustomed to under fixed rates. The dynamics of the wholesale electricity market will be reflected in the prices paid by retail customers. As an example, I pointed out in my direct testimony that the FirstEnergy utilities' recent auctions in Ohio and New Jersey resulted in pricing that is well in excess of prices paid today by Pennsylvania's FirstEnergy retail customers under fixed rates.

The Applicants' proposed merger will result in increased concentration in the various wholesale markets in which the FirstEnergy Companies and other Pennsylvania electric utilities must secure power supplies, in particular to fulfill their provider-of-last-resort ("POLR") obligations. This increased concentration creates the potential for the exercise of market power. Such potential, in fact, will translate into embedded, higher risk premiums in the prices at which future power supplies will be made available. Electricity generation suppliers will seek to be adequately compensated for the risks they perceive they will be incurring by entering into supply arrangements for POLR service. Participants which enter into transactions in a marketplace which is characterized by some participants having the potential for the exercise of market power will perceive this as a risk exposure and either incorporate this risk premium into their prices or will require contractual terms which allocate the risks to the utilities. Either way, POLR customers will ultimately pay a higher price than otherwise. In my direct testimony, I pointed out the example of the well publicized exercise of market power in the daily capacity market in PJM in 2001, which resulted in rule changes within PJM hopefully to prevent a re-occurrence. Subsequently, term capacity transactions in the PJM market continue to reflect a "rules" premium. Market power, once demonstrated, has had a long-term, lingering effect on capacity prices in PJM.

My point is not that future electricity prices will necessarily be higher than historical levels. I am not offering an opinion on the future level of electricity prices, which will be determined by a variety of factors including, but not limited to, fuel prices, institutional structures within which the industry operates, economic growth, environmental rules and laws, transmission investment and other factors. What is of concern to the FirstEnergy Companies related to Applicants' proposed merger is that, whatever the level of future prices, the merger will result in prices incrementally higher than they would have been absent the merger, due to the increased concentration of supply and the increased perceptions of the ability for the merged entity to exercise market power.

Q. **"2. The innovative and controversial nuclear "virtual divestiture" component of the FERC decision appears to present intriguing opportunities for the Commonwealth. Does the proposed merger present this Commission with an opportunity to create an additional economic development program designed to improve Pennsylvania's business climate by creating strategic partnerships with the public and private sector that support product development and the use of energy-efficient technologies?"**

A. It is difficult to see how the Applicants' virtual divestiture proposal would achieve this objective. It is clear that the Applicants' proposal to sell the output of certain its nuclear plants is designed to occur at market prices. For example, to the extent an auction process is used to implement virtual divestiture, the Applicants propose an ascending clock, multiple-round auction. While the precise mechanics of Applicants' virtual divestiture proposal have yet to be revealed, it appears that these sales will occur at market prices. These market prices may very well exceed the generation prices implicit in the FirstEnergy Companies' existing retail rates.

*Accordingly, as I indicated above and in my direct testimony in this proceeding,* I believe the merger as proposed, with no further market power mitigation efforts by the Applicants, will on balance deprive Pennsylvania of potential opportunities for further economic development and an enhance business climate. The primary concern of customers is price. As POLR rates begin to reflect true market prices, the current projections indicate that retail customers will see increases, not decrease, in pricing. The proposed merger will not contribute to lower market prices, and could result in higher market prices.

Q. **"3. Would it be possible to set aside 10% or some relatively small share of the "virtually" divested generation to augment economic development and economic competition with the Commonwealth? For example, could the parties consider and comment on creating a pool of energy and capacity of at least 260 MWs which could be used at the discretion of the Secretary of the Department of Community and Economic Development to attract and retain business in the Commonwealth?"**

A. The concept suggested by the question is highly problematic. First, setting aside a percentage of divested generation is not currently a part of the Applicants' proposal, and presumably would require their consent, as well as subsequent approval by the Federal Energy Regulatory Commission as part of the Applicants' compliance plan.

Moreover, setting aside this pool of low cost energy would impact market prices. If electric generation service is to be truly price competitive, such an artificial limit to market availability should be discouraged. Although I am not a lawyer, as someone who is familiar with regulatory requirements impacting electric generation I also would question whether, or the extent to which, such arrangements would be consistent with or permitted under the Electricity Generation Customer Choice and Competition Act.

In addition, the selection of winners and losers among Pennsylvania business and industry consumers in terms of gaining access to the prescribed portion of energy and capacity would be a constant source of debate and litigation. This selection process would of necessity involve a selection of one or more distribution utilities' service areas over others. Businesses and industries across the service areas of Pennsylvania's distribution utilities deserve equal access to the "best" deals available for acquiring electric generation service. Unavoidable inequities among distribution utility service providers, due to geography or transmissions constraints, could compromise the ability of businesses or industries to acquire competitive electricity generation sources.

**Q. "4. Could the Commonwealth through one of its agencies and/or in conjunction with a licensed Electric Generation Supplier facilitate the use of the output of this generation?"**

A. This suggestion has the same problems as expressed above. In addition, putting the Commonwealth or an EGS provider in the position of picking winners and losers would cause significant problems in administering an open and competitive retail electricity generation market.

If the Commonwealth of Pennsylvania desires to encourage a broad diversity and base of generation sources, it would be better served to provide tax credits to developers of projects that meet various Commonwealth policy goals, and leave the actual sale of power to the marketplace. This alternative legislation could be structured so as to be consistent with the current policy goal of encouraging a competitively priced, and unregulated, electricity generation market.

<u>**Surrebuttal to Joint Applicants' Rebuttal Testimony**</u>

**Q. Mr. Byrd, have you reviewed the written rebuttal testimony filed by Mr. O'Brien (PECO Statement No. 1-R) ?**

A. Yes, I have.

**Q. Is there any portion of his rebuttal testimony, concerning matters you addressed in your direct testimony, which you wish to address further?**

A. Yes. Mr. O'Brien correctly states (at page 15, lines 4-6, of his rebuttal testimony) that several parties, including the FirstEnergy Companies, have expressed concern that the proposed merger will result in market power and that the Applicants' proposed mitigation plan is insufficient to curb potential exercises of such power. Mr. O'Brien then proceeds to testify (at page 15, line 11) that "nearly" all of the analyses and arguments presented by the opposing parties were reviewed and rejected by the FERC Order approving the merger and, further (at lines 14-15), that FirstEnergy's direct testimony in this case consists simply of "the same statements it earlier filed at FERC". This part of Mr. O'Brien's testimony is incomplete and potentially misleading with respect to the FERC Order approving the proposed merger, and incorrect with respect to the FirstEnergy Companies' position.

**Q. Why is Mr. O'Brien's referenced testimony incorrect with respect to the FirstEnergy Companies' position?**

A. The FirstEnergy Companies' testimony in this proceeding included, but was not limited to, the testimony of Ms. Julia Frayer. It is correct to state that Ms. Frayer did submit, as an exhibit in this proceeding on the FirstEnergy Companies' behalf, a copy of her counterpart FERC testimony concerning the market power concerns with the Applicants' proposed merger. This submission directly corresponded to the FERC testimony Dr. Hieronymus likewise submitted in this proceeding.

However, the FirstEnergy Companies' position in this proceeding also included several points that I made in my written direct testimony, which were not directly addressed in the FERC Order. Perhaps that is the context within which Mr. O'Brien testified that "nearly" all opposing arguments were reviewed and rejected by FERC.

In addition, as Ms. Frayer discusses in her surrebuttal, it is misleading to state that FERC has completely rejected the market power concerns raised by the FirstEnergy Companies and others in their FERC protests and testimony, or to imply that the FERC Order eliminates any competitive concerns raised by the proposed merger.

In any case, the FirstEnergy Companies' concerns about the potential exercise of market power resulting from this proposed merger include some matters addressed by the FERC Order, and additional matters not addressed therein.

**Q. What previously expressed concerns set forth in your testimony were not addressed by the FERC Order?**

A. My overriding concern related both specifically to the FirstEnergy Companies in Pennsylvania, and generally for the emerging competitive market in Pennsylvania for POLR service, is that the existence of this merger will drive electricity prices up irrespective of any explicit findings of abuses of market power. This inevitable consequence of permitted the proposed merger should not be ignored.

**Q. Was this aspect of the proposed merger addressed in the FERC Order?**

A. No, it was not addressed, at least directly. However, as Ms. Frayer points out in her surrebuttal testimony to the rebuttal submitted by Dr. Hieronymus (Met-Ed/Penelec/Penn Power Statement No. 3-S), the FERC Order requires specific follow-up measures to be undertaken by the Applicants in order to ensure that what is being presumed about the success of current mitigation plans to curb potential market power abuses in fact occurs. Thus, it is clear that the FERC did not reject the need for further market power analyses of the proposed merger once the specific units to be divested and the purchasers are identified. In fact, FERC has concluded that the impact on competition cannot be determined until some future date at which the Applicants' specific divestiture plans become known. Just as importantly, FERC has retained the right to order additional mitigation if the Applicants' divestiture plans prove to be inadequate.

**Q. What are the implications of this for the Commission?**

A. I do not believe that the Commission can conclude at this point in time that the proposed merger will not adversely impact retail competition. It is clear that the proposed merger's impact on competition will be the subject to review and determination in a future FERC proceeding, and that additional mitigation may be required.

**Q. What course of action do you recommend for the Commission to take under these circumstances?**

A. I believe the Commission should make any approval of the proposed merger contingent on its examination, in a further proceeding, of the further steps to be completed pursuant to the FERC Order. This specific conditional provision should ensure that any subsequent analyses submitted by the Applicants or others can be examined as part of this Commission's further proceeding upon the completion of actual divestiture activities. Such a follow-up proceeding would be consistent with this Commission's examination of market power concerns as part of its overall review of the proposed merger.

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

A. Yes.

Met-Ed/Penelec/Penn Power Statement No. 2

+ Appendix A + EXS RAD-1-4 9K 9-22-05 Phila

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION



RE: JOINT APPLICATION OF PECO ENERGY COMPANY
AND PUBLIC SERVICE ELECTRIC AND GAS
FOR APPROVAL OF THE MERGER OF
PUBLIC ENTERPRISE GROUP INCORPORATED
WITH AND INTO EXELON CORPORATION



DOCKET NO. A-110550F0160

TESTIMONY
OF
RICHARD A. D'ANGELO

Met-Ed and Penelec Restructuring
Generation Plant Divestiture
Failure of Competitive Default Service Program
Wholesale Market Impacts on Retail Provider of Last Resort Service
Current Retail Provider of Last Resort Service Costs and Competitive Shopping

# TESTIMONY OF RICHARD A. D'ANGELO

## I. Introduction and Purpose

**Q. Please state your name and business address.**

A. My name is Richard A. D'Angelo and my business address is FirstEnergy, P.O. Box 16001, Reading, Pennsylvania 19612-6001.

**Q. Mr. D'Angelo, by whom are you employed and in what capacity?**

A. I am employed by FirstEnergy Service Company as Manager -- Rates and Regulatory Affairs – Pennsylvania. FirstEnergy's Pennsylvania Rate Department conducts regulatory support for Metropolitan Edison Company ("Met-Ed"), Pennsylvania Electric Company ("Penelec") and Pennsylvania Power Company ("Penn Power") (collectively, the "Companies"). I report to the Director of Rates & Regulatory Affairs and am responsible for the development, coordination, preparation and presentation of the Companies' accounting and financial data in all their rate-related matters before the Pennsylvania Public Utility Commission ("PUC" or "Commission") and the Federal Energy Regulatory Commission ("FERC"), as well as the preparation of statements and reports addressing, among other things, stranded cost recovery, energy costs, non-utility generation ("NUG") costs, quarterly earnings, and other financial matters. Also, I am responsible for the administration of the Companies' tariffs, development of retail electric rates and rules and regulations ensuring uniform administration and interpretation.

**Q. What is your educational and professional background?**

A. I graduated from Brooklyn College in 1972 with a Bachelor of Science degree in Economics and Pace University in 1976 with a Masters in Business Administration degree in Finance. I have over twenty eight years of experience with Met-Ed/GPU Energy/FirstEnergy Corp. My work experience is more fully described in Appendix A.

My most recent work experience has included the preparation and presentation of accounting and ratemaking testimony before the PUC in the Met-Ed/Penelec electric generation restructuring proceedings at Docket Nos. R-00974008 and R-00974009, pursuant to Pennsylvania's electric utility generation competition act, Public Utility Code Chapter 28. I also participated actively in the negotiation and completion of the Met-Ed/Penelec restructuring settlement ("Settlement"), which the PUC approved in October of 1998 (the Met-Ed/Penelec "Restructuring Plan"). Thereafter, I supervised the preparation and filing of the ratemaking and accounting report to the PUC as part of Phase 2 of the Met-Ed/Penelec Restructuring Plan, which incorporated the actual results of the completed generation asset divestiture transactions that had been approved previously by the PUC. I also prepared and submitted accounting and ratemaking testimony as part of the Phase 2 proceeding, which was concluded by a PUC order entered in December 2000.

As part of my continuing responsibilities as Manager-Rate Activity, I prepared and submitted accounting and ratemaking testimony in proceedings held before the PUC in 2001 at Docket Nos. P-00001860 and P-00001861, concerning the impact of escalating competitive electricity market costs on Met-Ed and Penelec in their role as provider of last resort ("POLR").

**Q. On whose behalf are you testifying in this proceeding?**

A. I am testifying on behalf of the Companies. In particular, my testimony focuses on the continuing POLR responsibilities of Met-Ed and Penelec following their generation asset divestiture and the flow-through of all of their net proceeds from these sales to their customers. I will refer to the merger parties of PECO and PSE&G hereafter as the "Applicants".

**Q. Please describe the purpose of your direct testimony.**

A. This testimony provides summary background and the context within which the PUC should view the concerns and recommendations the Companies have about the potential impact of the proposed merger.

My testimony (1) provides an overview of the Met-Ed/Penelec Settlement and Restructuring Plan, (2) discusses their sale of generation assets and flow-through of proceeds to their customers, (3) describes the failure of the competitive default service ("CDS") program under their approved Restructuring Plan, (4) describes the current situation of Met-Ed and Penelec as it relates to POLR responsibilities under the Settlement and Restructuring Plan, and the impacts the wholesale market has on those responsibilities, and (5) summarizes the impacts of high wholesale supply costs on POLR service and competitive shopping in the Companies service territories.

**Q. Mr. D'Angelo, have you prepared exhibits to accompany your testimony?**

A. Yes. FirstEnergy Exhibits RAD-1 through RAD-4 have been prepared by me or under my supervision and are described in detail in my testimony.

## II. Met-Ed and Penelec Restructuring

**Q. When was the Settlement reached and approved by the PUC?**

A. A joint petition for settlement, dated September 23, 1998, was filed with the Commission on September 24, 1998 at Docket Nos. R-00974008 and R-00974009. The PUC issued a Tentative Order approving the Settlement on the same date subject to consideration of all timely filed comments.

On October 20, 1998 the PUC entered an Order adopting a Settlement of the Met-Ed and Penelec restructuring proceedings as being in the public interest.

**Q. Please describe the major aspects of the Met-Ed/Penelec Settlement and approved Restructuring Plan that addressed the retail competitive market in Pennsylvania.**

A. Met-Ed/Penelec were required to sell their generation assets at fair market value to third parties unaffiliated with the companies but prohibited from placing further puts, calls, or other options in place as a condition of the divestiture process. As part of the Settlement, all divestiture proceeds were used to offset the companies' stranded costs. A second phase of the proceeding (Phase 2 as identified above) was conducted to determine a final stranded cost amount based on actual divestiture results.

Among the various issues resolved by the Settlement, were the unbundling of retail rates, reduced rates to retail consumers, and the commencement of retail competitive shopping in the Met-Ed and Penelec service territories beginning January 1, 1999.

The Settlement and approved Restructuring Plan contained important provisions addressing POLR service and the establishment of a CDS for up to 80% of the POLR load to enhance the development of retail competitive supply markets predicated on the divestiture.

The Settlement included a provision specifically prohibiting Met-Ed/Penelec from engaging in marketing activities related to its default POLR responsibilities.

The CDS provision was expected to provide non-shopping customers with an opportunity to realize bill savings. In a Joint Statement of Chairman John M. Quain and Commissioner Aaron Wilson, Jr. supporting the Tentative Order entered September 24, 1998 it was noted that "a competitive market for provider of last resort service will be established so that non-shopping customers also have an opportunity to realize bill savings."

## III. Generation Plant Divestiture

**Q. What was the underlying rationale for the Commission's approval of the divestiture of the Met-Ed/Penelec generation assets?**

A. The Commission approved the divestiture of Met-Ed's and Penelec's generation assets as in the public interest anticipating that a vibrant competitive market for retail electric generation competition would develop.

The Commission's Met-Ed/Penelec Restructuring Plan order noted that "The Companies are to divest themselves of their generation. Divestiture proceeds offset stranded costs. The Companies will apply net proceeds from the divestiture of its generation assets to offset stranded costs."

**Q. What terms and conditions surrounded the divestiture of Met-Ed and Penelec generation assets?**

A. The Settlement and approved Restructuring Plan provided for the divestiture of Met-Ed and Penelec generation assets at the highest prices reasonably achievable with the proceeds to be used to benefit customers by substantially reducing stranded costs. The Commission found that this would benefit consumers, it was in the public interest and the parties anticipated the development of a vibrant competitive market with many alternative generation suppliers.

**Q. Did Met-Ed/Penelec retain any rights in the divested generation assets?**

A. No. They did not retain any rights in the divested generation assets, beyond those previously incorporated into the approved Restructuring Plan, in order not to impair or reduce the fair market value of such assets.

## IV. <u>Competitive Default Service Program</u>

**Q. Please describe Met-Ed and Penelec's POLR obligations under the Settlement and approved Restructuring Plan.**

A. As the POLR suppliers for their retail customers who did not choose or could not choose to purchase power from suppliers other than Met-Ed and Penelec, both companies agreed that retail default service to their retail customers would be provided via a CDS competitive bid process under the following schedule: 20% on June 1, 2000; 40% on June 1, 2001; 60% on June 1, 2002; and 80% on June 1, 2003.

Commencing on January 1, 2001, the Settlement and approved Restructuring Plan also provided for the PUC to conduct an annual review of the CDS process to consider whether it was still in the public interest to continue to implement the above-mentioned schedule.

**Q. How were the rules developed to implement the CDS process?**

A. A collaborative approach with the signers of the Settlement was used to establish rules for CDS in the service territories of Met-Ed and Penelec, including bidding blocks, competitive bidding and other options to procure generation that would reduce costs and maximize customer benefits. The Commission also developed qualifications for credit worthiness and increased bond amounts for electric generation suppliers prior to the CDS initial competitive bid. The approved Restructuring Plan further provided that any bid for CDS exceeding Met-Ed's and Penelec's respective generation rate caps would be rejected and if no qualified bids for CDS were received at or below their generation rate caps, Met-Ed and Penelec would continue to provide POLR service at their respective rate cap levels unless they filed with and received approval from the Commission to provide POLR service at rates that exceeded the rate cap levels.

**Q. Has the CDS process been successful for Met-Ed and Penelec?**

A. No, the robust competitive bidding process that was envisioned at the time of the PUC's approval of the Met-Ed/Penelec Restructuring Plan never materialized, as was demonstrated by the failed first competitive CDS bid for alternative default suppliers to meet the 20% goal of retail customers POLR service being supplied by alternative suppliers.

Neither Met-Ed nor Penelec received any bids in response to their CDS program. The unsuccessful result of this CDS bid process was communicated to the Commission as part of Met-Ed's and Penelec's February 2, 2000 comments filed to the Commission's Tentative Order. As part of the comments Met-Ed and Penelec requested from the Commission a withdrawal of their CDS petition. Subsequently the Commission entered an order on March 16, 2000 granting their request.

**Q. Were any subsequent efforts made by Met-Ed and Penelec to solicit bids to meet their CDS obligations under the Settlement?**

A. Yes. Met-Ed and Penelec issued a second Request for Proposal ("RFP") for energy and capacity as a "wholesale CDS". That RFP sought bids from qualifying entities willing to assume up to 20% of Met-Ed and Penelec's load serving entity obligation in PJM for a one-year period commencing June 1, 2000. Unlike the previous CDS bidding process, the "wholesale CDS" did not seek to transfer the POLR obligation to a third party or require direct retail customer interface such as customer care responsibilities. In order to maximize the chances of receiving reasonable market-based bids, this second bidding process did not require bidders to offer rates at or below the companies' respective generation rate caps.

**Q. What were the results of this second RFP?**

A. The companies received bids in response to this "wholesale CDS" program. However, all of the bids were above Met-Ed and Penelec's generation rate caps. Additionally the lower bids were designed to be withdrawn if certain conditions were not met. Those conditions included even very minor changes in the PJM wholesale market, making the likelihood of a selected bidder supplying generation for the entire period remote.

**Q. What conclusions can be reached from the failed CDS program effort?**

A. The failure of the Met-Ed/Penelec efforts to obtain retail CDS bids at or below their generation rate caps, and the subsequent failure of the wholesale CDS bidding process, indicates that wholesale market prices were higher than the generation price implicit in the retail capped rate structure. The failure of the CDS program is indicative of the broader problems in obtaining robust retail competitive shopping in Pennsylvania's retail generation market. Since current retail rates that include generation rate caps do not permit a true reflection of wholesale market prices, many competitive suppliers generally have avoided the Pennsylvania retail market. High wholesale prices that translate into high retail prices can only be exacerbated by concentration of generating assets.

## V. Wholesale Market Impacts on Retail POLR Service

**Q. Since Met-Ed and Penelec divested their generation assets as part of their restructuring activity how do they service their POLR obligation?**

A. Without owned generation resources, Met-Ed and Penelec must procure most of their energy and capacity needs from the wholesale market to meet retail POLR obligations. There are three primary resources available to fulfill the retail energy and capacity needs: purchases from NUGs, purchases under contract from FirstEnergy Solutions ("FES") and other purchase power contracts. In addition, Met-Ed still owns and operates a small 20 MW hydro station, York Haven Hydropower Station.

**Q. Please describe the use of NUG generation output to serve the Met-Ed and Penelec retail POLR commitments.**

A. As part of the Settlement and Restructuring Plan, Met-Ed and Penelec use the energy and capacity of NUGs to serve a portion of their POLR obligations. The Settlement established a structure for valuing the output of each project for POLR accounting. Payments above this market value of the output are recovered through the stranded cost recovery mechanism.

**Q. How is the market value of the output of the NUG purchases determined?**

A. The companies value the NUG output, i.e. energy, of each project by multiplying the hourly locational marginal price at the NUG project's bus by the NUG project's output for that hour. The capacity value of each NUG project is based on daily, monthly and seasonal capacity auctions held by PJM to determine a monthly weighted average clearing price for all auctions. The monthly weighted average auction clearing price is multiplied by the NUG project's monthly unforced capacity. The summation of the energy and capacity values is the POLR cost to Met-Ed and Penelec for their respective projects.

**Q. Please describe the energy and capacity supply arrangements that Met-Ed and Penelec have with FES.**

A. Shortly after the merger between FirstEnergy and GPU, Inc. was completed in 2001, an energy and capacity agreement was signed by Met-Ed and Penelec with FES for the bulk of their energy and capacity requirements. Since the companies already had a portion of their retail POLR requirements covered with NUG contracts and some purchase power contracts, the arrangements with FES were designed to meet the companies' remaining obligations. Witness Byrd discusses these arrangements in Met-Ed/Penelec/Penn Power Statement No. 1.

**Q. What is the current price for the contract with FES?**

A. The basic pricing structure of the contract with FES utilizes the respective Met-Ed and Penelec average retail generation tariff rate less gross receipts tax and adjusted for line losses as contained in the companies' supply tariffs. For Met-Ed the price is $41.65 per mwh. For Penelec the price is $41.41 per mwh.

**Q. What are the basic terms and conditions of the Met-Ed and Penelec supply arrangements with FES?**

A. The contract Met-Ed and Penelec have with FES does not have a termination date but can be cancelled by either party by November 1st of each year. The contract is renewed each year unless either party exercises its ability to terminate the arrangement.

**Q. Please describe the other purchases the companies use to meet their POLR obligations.**

A. A portion of the retail POLR commitments of Met-Ed and Penelec are met through purchase power contracts in their own names. When favorable pricing opportunities have been available, Met-Ed and Penelec procure energy and capacity contracts to meet their POLR load obligations. This primarily reduces the Met-Ed and Penelec wholesale market exposure, captures favorable pricing and provides a hedge if/when the FES contract for energy and capacity is terminated.

**Q. Are the Companies impacted by the operations of the wholesale energy and capacity markets?**

A. Yes. Met-Ed and Penelec, and ultimately their retail customers, have significant exposure to the wholesale energy and capacity markets. Their divestiture of generation assets to foster retail competition and to help reduce stranded costs their customers would have to pay, leaves them dependent upon a properly functioning wholesale market to meet their retail POLR obligations.

Penn Power and its customers are also exposed to wholesale energy and capacity market risk, although to a lesser degree than Met-Ed and Penelec.

**Q. How are the Companies' impacted by the operation of the wholesale energy and capacity markets?**

A. Since the Companies are dependent upon purchases of energy and capacity in the wholesale market to meet their retail POLR requirements, rising wholesale energy and capacity prices make it difficult to meet these obligations while preserving the retail generation rate caps. Penn Power's generation rate cap expires at the end of 2006. The Met-Ed and Penelec generation rate caps expire at the end of 2010.

Also, the portion of their POLR requirements that would be met by NUG output has always been subject to variable wholesale market prices that have been constantly rising. These combined impacts put significant financial pressure on Met-Ed and Penelec to meet their retail POLR obligations under the retail generation rate caps. Rising wholesale market prices also jeopardizes the viability of the companies' existing energy and capacity partial service requirements contract. In short, further rising energy and capacity costs are putting the retail generation rate caps under severe pressure at Met-Ed and Penelec.

## VI. Current Retail POLR Service Costs and Competitive Shopping

**Q. What is the current level of POLR supply costs experienced by Met-Ed and Penelec?.**

A. These companies have three different sources of energy and capacity supply costs to meet their retail POLR obligations. Met-Ed/Penelec Exhibit RAD-1 is three-page exhibit that shows the energy source, the mwhs and the cost of energy and capacity for the companies by year. Year 2004 is actual data while 2005 is a combination of actual and forecasted information. The final year, 2006, is all forecast information.

As can be seen from Met-Ed/Penelec Exhibit RAD-1, the costs of supplying energy and capacity have been steadily rising and can best be seen by tracking the valuation of NUG energy and capacity. For Met-Ed, NUG costs at market rise from $43.76/mwh in 2004 to $45.92/mwh in 2005 and $49.16/mwh in 2006. For Penelec, NUG costs at market increase from $40.91/mwh in 2004 to $45.95/mwh in 2005 and $49.24/mwh in 2006. Since the energy prices of the NUG output is valued each hour at each bus and capacity is valued monthly, this is a good indicator of the price at which NUG production is clearing at in the marketplace.

The contract supply from FES is at a constant fixed price of $41.65/mwh for Met-Ed and $41.41/mwh for Penelec. The price for energy and capacity purchases from FES are fixed for all three years during this period although the supply varies from year-to-year. However, if FES exercises its option to terminate the supply contract by November 1st, the replacement energy and capacity costs for this component of the supply portfolio would increase significantly.

The other purchases increase from the low $30/mwh range in 2004 for Met-Ed to the mid to upper $30/mwh range by 2006. For Penelec, these values are in the mid to upper $30/mwh range throughout the period.

Overall, total energy and capacity costs are in the low $40/mwh range during the period.

**Q. Has Met-Ed been experiencing retail POLR losses?**

A. Yes. Met-Ed/Penelec Exhibit RAD-2 uses the same POLR supply cost information contained in Met-Ed/Penelec Exhibit RAD-1 but includes generation revenue. This makes it possible to calculate a gain or loss on retail POLR supply. Met-Ed experienced about a $40 million loss in 2004. In 2005 the losses are forecasted to be about $34 million. The loss is expected to moderate somewhat in 2006 because Met-Ed will have a five percent increase in its retail generation charge in accordance with the terms and conditions of the Settlement. Nevertheless, the cost pressures will continue in 2006 and beyond as wholesale market prices continue to rise.

**Q. Has Penelec been experiencing retail POLR losses?**

A. Yes. Met-Ed/Penelec Exhibit RAD-3 uses the same POLR supply cost information contained in Met-Ed/Penelec Exhibit RAD-1 but includes generation revenue. This makes it possible to calculate a gain or loss on retail POLR supply. Penelec experienced about a $40 million loss in 2004. In 2005 the loss is forecasted to be about $30 million. The loss is expected to moderate somewhat in 2006 because Penelec will have a five percent increase in its retail generation charge in accordance with the terms and conditions of the Settlement. As we saw at Met-Ed, the cost pressures will continue in 2006 and beyond as wholesale market prices continue to rise.

**Q. Has the high wholesale market prices for capacity and energy affected the abilities of customers to shop for competitive supply choices?**

A. Yes. Met-Ed/Penelec/Penn Power Exhibit RAD-4 is a comparative analysis of shopping statistics in the Companies retail service territories from 1999 through May 2005.

For Met-Ed, shopping peaked in the first year of retail competition back in 1999 with almost 35,000 customers, or 6.93%, seeking alternative competitive suppliers. By 2000, the number had fallen to below 29,000 customers, or 5.75%, shopping competitively before dropping below 2,000 customers, or 0.38%, shopping in 2001. In 2004 and 2005 the number of customers shopping from alternative suppliers was under 1,000, less than two-tenths of one percent, in each year.

For Penelec, shopping peaked in the first year of retail competition back in 1999 with close to 33,000 customers, or 5.73%, seeking alternative competitive suppliers. The number dropped to about 27,000 customers, or 4.74%, shopping competitively in 2000. Similar to Met-Ed, the number of customers shopping competitively in 2001 dropped to around 2,000 customers, or 0.38%. In 2004 and in 2005 the number of customer shopping from alternative suppliers hovered around 1,000, or about two-tenths of one percent, seeking competitive alternative suppliers.

For Penn Power, shopping peaked in the first year of retail competition back in 1999 with about 10,000, or 6.6%, customers seeking alternative competitive suppliers. By 2001, the number had fallen to below 1,500 customer, or 0.90%, shopping competitively before dropping to just a couple of hundred of customers, less than one-half of one percent, shopping in subsequent years.

**Q. What conclusions can be drawn from the above shopping statistics in Met-Ed, Penelec and Penn Power service territories?**

A. While competitive shopping began with a good start (with over 6% of the companies' combined customers, and almost 40% of customer load, buying from alternative competitive suppliers back in 1999), the number of customers and customer load dropped off significantly as wholesale market prices steadily rose. High wholesale market prices inhibit the development of competitive retail markets and retail shopping in Met-Ed, Penelec and Penn Power service territories.

## VII. Conclusions

**Q. Mr. D'Angelo, what conclusions can be reached about the impact of wholesale market prices on the Companies and their customers?**

A. Rising wholesale market prices for energy and capacity during the generation rate cap period negatively impacts the Companies since they are currently unable to recover their power supply costs above their respective generation rate caps. This can been seen from the steadily rising POLR supply costs experienced by Met-Ed and Penelec and the likelihood of further increasing POLR supply costs over the ensuing years. Ultimately, these rising energy and capacity costs will be passed through to Met-Ed, Penelec and Penn Power customers either during the retail generation rate cap period or when the generation rate cap terminates and the fixed retail generation rate is replaced with a retail market rate.

**Q. Will the PECO-PSE&G merger alleviate the wholesale supply situation?**

A. No. From my understanding of Witness Frayer's testimony (Met-Ed/Penelec/Penn Power Statement No. 3), concentration of generation assets may result in higher wholesale prices that can only exacerbate the problem. The existing steadily rising wholesale prices may be impacted further, causing retail customers harm by raising prices without any corresponding benefits.

**Q. What is your recommendation in this proceeding?**

A Although my testimony has focused on the impact of the wholesale market on costs experienced by the Companies, and ultimately its retail customers, the PUC must protect retail customers in all regulated service territories. The Commission must protect retail customers by preventing unwarranted concentration of generation assets which is not in the public interest, and assuring that the Applicants' post-merger market power and the anticompetitive effects of the merger will be mitigated.

**Q. Mr. D'Angelo, does this complete your direct testimony?**

A. Yes, it does.

Resume: Education and Experience of Richard A. D'Angelo

Education:

| | |
|---|---|
| 1972 | Bachelor of Science Degree in Economics - Brooklyn College |
| 1976 | Master of Business Administration Degree in Finance - Pace University |

Experience:

| | |
|---|---|
| 9/72 - 11/76 | Accountant and Supervisor - Bankers Trust Company |
| 11/76 - 2/81 | Employed as Accountant within Regulatory Accounting Area - Metropolitan Edison Company ("Met-Ed") |
| 2/81 - 2/82 | Senior Accountant within Regulatory Accounting Area with special emphasis on rate-related matters (Met-Ed) |
| 2/82 - 2/83 | Supervisor - Rates and Financing (Met-Ed) |
| 2/83 - 3/95 | Manager - Rate Revenue Requirements within the Rate Department (Met-Ed) |
| 3/95 - 8/96 | Manager - Regulatory Liaison within the Regulatory Affairs and Pricing Department (Met-Ed/Penelec) |
| 8/96 – 11/01 | Manager - Rate Activity within the Rate Department (GPU Energy) |
| 11/01 – Present | Manager – Rates & Regulatory Affairs- Pennsylvania (FirstEnergy) |

Prepared and presented testimony in the following rate-related cases:

Pa. P.U.C. Cases: Docket Nos. R-00016851C0001
R-00016852C0001
R-00016853C0001
A-110300F.0095
A-110400F.0040
P-00001860
P-00001861
P-00001837 (Phase 2)
P-00001838 (Phase 2)
R-00974008 (Phase 1)
R-00974009 (Phase 1)
P-00971215
P-00971216
P-00971217
P-00971223

P-00971278
P-00961015
P-00950968
A-110300 F0067
R-922314
P-0092087
P-00900450
R-860384
R-842770
R-832549
R-822249
I-900005
P-890366
M-FACE 8707
M-FACE 8602
M-FACE 8506
M-FACE 8404
M-FACE 8203
M-FACE 8104
M-870171 C001

NJ B.P.U Case: Docket No. EO03121014

FERC Cases: Docket Nos. ER-90-388-000 and ER-90-522-000
ER-87-34-001
ER-83-173

Assisted in development and preparation in the following rate cases:

Pa. P.U.C. Cases: Docket Nos. R-811601
R-80051196
R.I.D. 626

FERC Case: Docket No. ER-79-58

**POLR Supply MWH and Costs**
**Met Ed and Penelec**
**2004**
Actual

| | Met Ed | | | Penelec | | |
|---|---|---|---|---|---|---|
| | MWH | Amount $000's | $/mwh | MWH | Amount $000's | $/mwh |
| Supply Source | | | | | | |
| NUGs @ market | 2,200,326 | $ 96,296 | 43.76 | 3,186,488 | $ 130,354 | 40.91 |
| York Haven Hydro | 140,469 | 3,003 | 21.38 | - | - | |
| FES supply | 10,430,046 | 434,411 | 41.65 | 9,748,038 | 403,666 | 41.41 |
| Other purchases | 747,719 | 24,242 | 32.42 | 941,226 | 36,331 | 38.60 |
| Total | 13,518,560 | $ 557,952 | 41.27 | 13,875,752 | $ 570,351 | 41.10 |

**POLR Supply MWH and Costs**
**Met Ed and Penelec**
**2005**
Forecast

| | Met Ed | | | Penelec | | |
|---|---|---|---|---|---|---|
| | MWH | Amount<br>$000's | $/mwh | MWH | Amount<br>$000's | $/mwh |
| Supply Source | | | | | | |
| NUGs @ market | 2,182,184 | $ 100,198 | 45.92 | 2,976,245 | $ 136,756 | 45.95 |
| York Haven Hydro | 125,994 | 3,671 | 29.13 | - | - | |
| FES supply | 7,765,938 | 323,451 | 41.65 | 7,044,444 | 291,710 | 41.41 |
| Other purchases | 3,983,200 | 146,146 | 36.69 | 3,813,600 | 142,065 | 37.25 |
| Total | 14,057,316 | $ 573,466 | 40.79 | 13,834,289 | $ 570,532 | 41.24 |

**POLR Supply MWH and Costs**
**Met Ed and Penelec**
**2006**
Forecast

| | | Met Ed | | | Penelec | | |
|---|---|---|---|---|---|---|---|
| | | MWH | Amount<br>$000's | $/mwh | MWH | Amount<br>$000's | $/mwh |
| Supply Source | | | | | | | |
| NUGs @ market | | 2,244,175 | $ 110,315 | 49.16 | 3,049,983 | $ 150,172 | 49.24 |
| York Haven Hydro | | 126,000 | 4,202 | 33.35 | - | - | |
| FES supply | (a) | 5,665,145 | 235,953 | 41.65 | 4,450,116 | 184,279 | 41.41 |
| Other purchases | | 6,604,400 | 240,072 | 36.35 | 6,840,400 | 254,004 | 37.13 |
| Total | | 14,639,720 | $ 590,542 | 40.34 | 14,340,499 | $ 588,455 | 41.03 |

(a) assumes current contract with FE Solutions remains in effect.

**Met Ed**
**POLR Revenue, Costs, and Gains or Losses**
**2004 - 2006**
**$000's**

**2004**

| | |
|---|---|
| POLR Revenue | $ 518,356 |
| POLR Cost | 557,952 |
| POLR Gain or (Loss) | $ (39,596) |

**2005**

| | |
|---|---|
| POLR Revenue | $ 539,052 |
| POLR Cost | 573,466 |
| POLR Gain or (Loss) | $ (34,414) |

**2006**

| | |
|---|---|
| POLR Revenue | $ 599,562 |
| POLR Cost | 590,542 |
| POLR Gain or (Loss) (a) | $ 9,020 |

(a) assumes current contract with FE Solutions remains in effect.

**Penelec**
**POLR Revenue, Costs, and Gains or Losses**
**2004 - 2006**
**$000's**

**2004**

| | |
|---|---|
| POLR Revenue | $ 530,031 |
| POLR Cost | 570,351 |
| POLR Gain or (Loss) | $ (40,320) |

**2005**

| | |
|---|---|
| POLR Revenue | $ 539,533 |
| POLR Cost | 570,532 |
| POLR Gain or (Loss) | $ (30,999) |

**2006**

| | |
|---|---|
| POLR Revenue | $ 593,954 |
| POLR Cost | 588,455 |
| POLR Gain or (Loss) (a) | $ 5,499 |

(a) assumes current contract with FE Solutions remains in effect.

**Metropolitan Edison Company**
**Shopping Statistics**
**1999 -- 2005**

| Year | Number of Customers Shopping | Percentage of Customers Shopping | Customer Load (MW) | Percentage of Customer Load Shopping |
|---|---|---|---|---|
| 1999 | 34,665 | 6.93% | 957.8 | 40.02% |
| 2000 | 28,762 | 5.75% | 671.8 | 28.07% |
| 2001 | 1,901 | 0.38% | 74.8 | 3.13% |
| 2002 | 1,486 | 0.30% | 132.4 | 5.53% |
| 2003 | 1,118 | 0.22% | 144.2 | 6.03% |
| 2004 | 951 | 0.19% | 146.4 | 6.12% |
| 2005 * | 852 | 0.17% | 121.0 | 5.06% |

* 2005 YTD through May

**Pennsylvania Electric Company**
**Shopping Statistics**
**1999 – 2005**

| Year | Number of Customers Shopping | Percentage of Customers Shopping | Customer Load (MW) | Percentage of Customer Load Shopping |
|---|---|---|---|---|
| 1999 | 32,961 | 5.73% | 929.6 | 35.85% |
| 2000 | 27,300 | 4.74% | 715.6 | 27.60% |
| 2001 | 2,186 | 0.38% | 152.9 | 5.90% |
| 2002 | 1,802 | 0.31% | 281.7 | 10.87% |
| 2003 | 1,408 | 0.24% | 215.7 | 8.32% |
| 2004 | 1,223 | 0.21% | 102.7 | 3.96% |
| 2005 * | 1,091 | 0.19% | 92.4 | 3.56% |

* 2005 YTD through May

**Pennsylvania Power Company**
**Shopping Statistics**
**1999 -- 2005**

| Year | Number of Customers Shopping | Percentage of Customers Shopping | Customer Load (MW) | Percentage of Customer Load Shopping |
|---|---|---|---|---|
| 1999 | 9,868 | 6.60% | 184.3 | 19.20% |
| 2000 | 9,612 | 6.40% | 84.6 | 8.81% |
| 2001 | 1,405 | 0.90% | 11.9 | 1.20% |
| 2002 | 615 | 0.40% | 2.6 | 0.30% |
| 2003 | 530 | 0.30% | 2.6 | 0.30% |
| 2004 | 469 | 0.30% | 2.4 | 0.30% |
| 2005 * | 424 | 0.30% | 2.3 | 0.30% |

* 2005 YTD through May

Met-Ed/Penelec/Penn Power Statement No. 3

+ Appendices A, B + C +
Ex S 3-A + B

JK
9-22-05
phila

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION



RE: JOINT APPLICATION OF PECO ENERGY COMPANY
AND PUBLIC SERVICE ELECTRIC AND GAS
FOR APPROVAL OF THE MERGER OF
PUBLIC ENTERPRISE GROUP INCORPORATED
WITH AND INTO EXELON CORPORATION



DOCKET NO. A- 110550F0160

TESTIMONY
OF
JULIA FRAYER

Analysis of Applicants' Market Power Mediation Steps
Response to Testimony Submitted on Applicants' Behalf by Dr. William Hieronymus

# TESTIMONY OF JULIA FRAYER

**Q. Please state your name, business affiliation and address.**

A. My name is Julia Frayer. I am a Partner and Managing Director of London Economics International LLC ("LEI"). My business address is 717 Atlantic Avenue, Suite 1A, Boston, MA 02111.

**Q. Ms. Frayer, please briefly describe your educational and professional background.**

A. As Managing Director of LEI, I currently direct many of the company's engagements involving market power analyses, strategic bidding and simulation modeling, and market design with respect to market power issues, regulation, and competition. I have also advised on retail market issues in the electricity sector. For those customers seeking to buy electricity, I have provided forecasts of wholesale and retail electricity rates and recommended procurement strategies based on their consumption profiles and market expectations, so I am very familiar with the concerns and considerations of final consumers when they review their retail options and consider wholesale market activities.

Last year, I assisted Connecticut's Department Of Public Utility Control's ("DPUC") Utility Operations and Management Analysis unit in monitoring the power procurement processes for Connecticut Light & Power's ("CL&P")

Transitional Standard Offer ("TSO") auction in November 2004. I provided testimony evaluating the auction process to the DPUC.

I have also consulted with many clients on the implications of market power created through mergers and acquisitions or structural changes in the market. Over the years, I have also worked with system operators, regulators, and state commissions on analyzing market power behavior and measuring its impact on deregulated electricity markets. Sample engagements in this field include analysis of power purchase agreements in Alberta during the market deregulation process in the late 1990s and development of holding restrictions to mitigate market power concerns in that jurisdiction's evolving wholesale market. I have also submitted testimony at the Federal Energy Regulatory Commission ("FERC") on merger applications and market-based rate applications. In January 2005, I testified on FERC's Technical Panel on the interim generation market power screens for market-based rate authorizations. I have also recently presented testimony on pricing safeguards and market power issues in front of the Public Utility Commission of Texas, and designed market power identification and amelioration mechanisms for the Department of Energy of Alberta.

A detailed summary of my credentials is set forth in Appendix A, attached to this testimony.

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

A. I have been retained by FirstEnergy Service Company to review, on behalf of FirstEnergy's Pennsylvania electric utilities (namely, Metropolitan Edison Company, Pennsylvania Electric Company and Pennsylvania Power Company, also collectively referred to as the "Companies"), the economic and market power related analysis that was conducted by Dr. William Hieronymus, on behalf of the PECO Energy Company ("PECO") and Public Service Electric and Gas Company ("PSE&G"), who are jointly referred to as the "Applicants" in my testimony, in their merger application filed with the Pennsylvania Public Utility Commission ("Commission" or "PUC") at Docket No. A-110550F0160. The analysis, conclusions, and recommendations of Dr. Hieronymus were submitted as part of the written direct testimony supporting the merger application filed with the PUC.

My direct testimony summarizes my analysis and conclusions concerning the deficiencies in the Applicants' market power mitigation plan. I believe the steps offered to date by the Applicants are insufficient to completely and truly mitigate market power concerns arising from this merger. To the extent that these deficiencies are not adequately addressed, the further development of Pennsylvania's retail electricity market could be adversely impacted.

**Q. Please describe the context within which you have conducted your review and analysis and offer recommendations for purposes of this PUC proceeding.**

A. The context for my review, analysis, and recommendations in this PUC proceeding is the provision in Pennsylvania law that requires the Commission to consider whether a proposed merger of electric utilities or electric suppliers is likely to result in anticompetitive or discriminatory conduct, including the unlawful exercise of market power that will prevent retail electricity customers in Pennsylvania from obtaining the benefits of a properly functioning and workably competitive retail electricity market. Dr. Hieronymus referred to this requirement as part of his direct testimony, namely, that the PUC should review such issues and resolve potential market power concerns that could adversely impact the development of Pennsylvania's competitive retail electricity market.

**Q. Is there a relationship between market power issues and concerns affecting the retail electricity market, which the PUC has an obligation to monitor and regulate, and similar issues and concerns arising at the FERC level?**

A. Yes. Although I am not a lawyer and would not offer any conclusions about the legal interrelationship between FERC and PUC jurisdiction, as an economist I am prepared to address the practical, economic relationship between the wholesale electricity market, governed by FERC, and retail competition in Pennsylvania. There is an explicit interconnection between the deregulated wholesale market and a vibrant retail electricity market. Under a fully deregulated market structure, the energy component in competitive retail tariffs is directly derived from appropriate regional wholesale market price indications. As such, any impact that increased market power has on regional wholesale price developments will flow through to final consumers who are exposed to a fully deregulated retail market.

By all accounts, Pennsylvania has a nascent, deregulated retail market. Though all consumers have been given the right to select competitive suppliers and leave their incumbent utility, they have also been granted an option to stay on default service with the incumbent utility where they are shielded from wholesale market considerations over the short-term through generation rate caps. Based on current arrangements, the Companies' generation rate caps expire in 2006 (Penn Power) and 2010 (Met-Ed and Penelec). Because of their obligation to supply Provider of Last Resort ("POLR") service to their customers under the rate freeze, the Companies are already financially exposed to higher wholesale market prices. If the "evergreen" contract with FirstEnergy Solutions is terminated, this exposure will increase as discussed in the direct testimony of William Byrd (Met-Ed/Penelec/Penn Power Statement No. 1) and Richard D'Angelo (Met-Ed/Penelec/Penn Power Statement No. 2). MetEd and Penelec have further exposure vis-à-vis their POLR commitments under the current environment due to their divestiture of their generation assets and the subsequent allocation of net proceeds from the sale of those assets to their ratepayers to offset stranded costs. Thus, the Companies must purchase electricity and capacity from the wholesale market, either directly from third-parties or in the short-term spot market administered by the relevant regional transmission organization.

Indirectly or directly[1], in the shorter or longer term, the Companies and their ratepayers will be exposed to wholesale market dynamics. Other utility companies in Pennsylvania face distinct, yet generally similar, issues with respect to the POLR requirement and the costs of wholesale electricity procurement. Ultimately, retail electric consumers in Pennsylvania are going to be confronted with an exposure to actual wholesale price dynamics in the post-rate freeze environment. A price shock, coupled with welfare losses, is possible if the post-transition pricing continues to escalate and, particularly, if potential market power is not mitigated at the earliest opportunity. Therefore, the PUC will want to fully consider the proposed merger's impact on retail electricity markets as affected by the wholesale market in the near future and over the longer term.

**Q. Can you describe in more detail the link between wholesale and retail markets?**

A. Load serving entities ("LSEs"), such as the distribution companies providing POLR services to their customers who choose not to switch to competitive suppliers, must secure reliable electricity service on behalf of their consumers. They do so by participating in the wholesale market for those services. Before we

[1] Direct participation is implied in the selection of a competitive supplier, while indirect participation is implied through the termination of the generation rate caps and recalibration of the POLR rates to then current wholesale market conditions for electricity.

delve further into the links between wholesale and retail markets, it is important to define electricity service from the perspective of retail consumers and market participants in the wholesale market.

Though retail consumers consider electricity only in terms of the kilowatt hours they see on their meters, the service they receive is in fact composed of more than just kilowatt hours. A retail tariff for residential or small commercial customers usually consists of full requirements service where electricity is provided as needed around-the-clock. Full-requirements services can be broadly described as consisting of:

1. a generation component (i.e., the cost of producing electricity and ensuring reliable system services through capacity payments and ancillary services),
2. a transportation component (the cost of transporting electricity from the point of production to the final consumer, e.g., transmission and distribution charges), and
3. miscellaneous charges (for stranded cost recovery, support payments of DSM and renewable programs, etc.).

The generation element is typically the largest component of full requirements service, usually comprising more than half of the total charges per unit of consumption in many jurisdictions.

Currently, in the market area covered by the PJM Interconnection ("PJM"), which includes the majority of Pennsylvania consumers, there are both short-term spot sales of electricity (Day-ahead and Real-time markets are operated by PJM) and forward sales (which are arranged through brokers and over-the-counter exchanges such as NYMEX), as well as market sales of installed capacity (which all LSEs must purchase on behalf of the final consumers in proportion to their peak demand needs), and certain ancillary services. The Penn Power portion of western Pennsylvania is under the Midwest Independent Transmission System Operator, Inc.'s ("MISO") jurisdiction, whose spot market for energy began in the spring of 2005. Appendix B to my testimony provides a map of the service territories of Pennsylvania's electric utilities vis-à-vis the market boundaries of PJM and MISO. Transmission and distribution charges, as well as certain classes of ancillary services, are priced on the basis of regulated or cost-of-service rates in both PJM and MISO market areas.

LSEs procure these various components of the full requirements service from the wholesale electricity market and then re-sell the packaged service to final consumers. Thus, final consumers in a fully deregulated, competitive retail electricity market would bear the costs of full requirements services, including the cost of producing electricity in a reliable manner. On that basis, the generation element in competitive retail tariffs is directly linked to conditions and price levels achieved in the wholesale market, where energy, capacity, and ancillary services are bought and sold.

**Q. What is the current status of retail market deregulation in Pennsylvania?**

A. While Pennsylvania's retail market has been restructured and consumers are free to choose their supplier, the rate freeze on the generation component of the retail tariff put in place through the state's original electric generation restructuring legislation in 1996 (and resulting PUC approved settlement agreements), has limited the amount of competitive activity especially in light of relatively high fuel price environment currently and resulting levels of wholesale electricity prices. The generation rate caps have insulated consumers from wholesale market dynamics.

As highlighted in the table, below, the Companies' generation rate caps are scheduled to expire in 2006 and 2010. Given the current level of wholesale market prices and the generation rate caps, most ratepayers have chosen to stay on POLR service.[2] However, as these generation caps expire over the next five years, the POLR services that the Companies provide will also be recalibrated based on then future wholesale market conditions. Indeed, electricity consumers representing over 22% of Pennsylvania's electricity demand will be met through market-oriented retail tariffs once all the Companies' generation rate caps expire (as highlighted in the table below).

[2] Switching rates in the Companies' district and the Companies' experience with POLR are discussed further in Richard D'Angelo's direct testimony.

**Table 1. List of generation cap expiration dates for the Companies and their share of the state's annual electricity load**

| Distribution utilities | Generation cap expiration (month-year) | Total state load 2003 (MWh) | Utility's share of state load | Cumulative share of state load |
|---|---|---|---|---|
| Penn Power | December-06 | 4,296,500 | 3% | 3% |
| Met-Ed | December-10 | 12,934,412 | 9% | 12% |
| Penelec | December-10 | 13,347,150 | 10% | 22% |

**Q. What implications does this have for the link between wholesale and retail prices in Pennsylvania?**

A. Currently, the link between wholesale and retail electricity markets has been severed for most electricity consumers in Pennsylvania through the imposition of the generation rate caps. The caps on the generation component of the retail tariff insulate POLR ratepayers from the actual cost of electricity in the wholesale market. Indeed, the POLR obligations for MetEd and Penelec have been a substantial cost burden to these companies, as discussed in the direct testimony of Richard D. Angelo.

Moreover, the fixed generation rate caps in today's relatively high priced electricity environment have dampened the potential for full-fledged retail electricity competition in the service territories of the Companies and more broadly in Pennsylvania. Many competitive retailers have not been able to develop a foothold in the Pennsylvania market as their costs of operation, based on wholesale market price levels for energy, capacity, and ancillary services that they must purchase, exceed the generation rate caps that the consumers can choose to take advantage of through POLR. In Appendix C to my testimony, I show the generation component of the regulated POLR tariff for residential customers at Penn Power, MetEd, and Penelec compared to the costs of full requirement service (consisting of average on-peak price of day-ahead electricity in their respective market areas for 2004 and estimated costs for capacity credits and ancillary services). Clearly, the residential generation rate cap is substantially below observed wholesale market pricing for electricity, capacity, and ancillary services in all three regions.

**Q. What is likely to occur to Pennsylvania ratepayers once the generation rate caps expire?**

A. Utilities will continue to provide services and meet their default supply obligation. However, retail consumers will no longer be insulated from wholesale market dynamics. Pennsylvania's 1996 electric generation restructuring law requires the PUC to develop plans delineating how incumbent utilities should continue to provide default service once the generation rate caps expire. In December 2004, the PUC proposed regulations for providing default electric generation service once the current POLR arrangements expire. Under the proposed regulations, utilities that provide default service to residential customers would be required to offer their existing customers at least one-year fixed-price contracts and to obtain their power through competitive bids at prevailing energy market prices (in the wholesale market). The retail customers will thus pay for electricity services consistent with wholesale market conditions at that time.

The price impact of the explicit re-linking of the retail and wholesale electricity markets will depend on price developments in the wholesale market for electricity, capacity, ancillary services, and other components of the full requirements service that small customers will seek out. Currently wholesale electricity prices are higher than the generation rate cap. Future wholesale price development will depend on fuel prices, the level of competition in the region, and other factors. Given the current level of gas and coal prices, and the forecasts for these fuels for the next few years, it is unlikely that we will see a significant drop in electricity prices in the PJM or MISO market areas over the short term. As commented on by William Byrd in his direct testimony submitted on behalf of the Companies, recent retail market auctions in the neighboring jurisdictions of New Jersey and Ohio indicate that competitive wholesale prices would produce relatively high retail prices. This suggests that consumers coming off the rate freeze will experience a price increase for electricity services, if wholesale prices are recovered in rates. This price shock is legitimate and a necessary part of the transition process to a competitive, fully deregulated retail market for electricity. However, market power created by the proposed merger, if left unchecked, would lead to even higher wholesale prices and ultimately impose a further economic burden on ratepayers with wealth transfer and other economic inefficiencies to detriment of a competitive and stable long run market for electricity.

**Q. How could market power created by the proposed merger affect Pennsylvania's consumers?**

A. As I discuss in my FERC testimony (see Exhibits 3-A and 3-B, further identified below and attached to my testimony), a merger of this magnitude, resulting in the combination of approximately 40,000 MW and pre-mitigation market shares in excess of 45%, creates enormous potential for the exercise of market power in wholesale markets for electricity (energy), capacity, and ancillary services. The abuse of market power can serve to decrease the effectiveness of price signals, leading to inefficient production and consumption decisions. If the Applicants' potential market power is not fully mitigated, Pennsylvania customers coming off the generation rate cap may face higher retail prices (as a result of wholesale market conditions) than they would have had to endure if the merger had not occurred.

**Q. How do these issues affect the Companies?**

A. Met-Ed and Penelec are particularly sensitive to wholesale market prices given (1) the divestiture of their owned generation assets to unaffiliated third-parties and credit of those net proceeds to ratepayers to offset stranded costs, and (2) the level and tenure of the rate freeze imposed. The direct testimony of the Companies' witnesses, Richard A. D'Angelo and William Byrd, provide further details of the Companies' operations and POLR supply obligations.

**Q. Do the Applicants' positions on market power, and their mitigation plan, overlap with their FERC filings?**

A. Yes. Dr. Hieronymus relies on the analysis and conclusions he submitted in the pending FERC proceeding governing this proposed merger as the basis for his support of the Applicants in the PUC proceeding. His analysis and recommendations that were submitted on behalf of the Applicants in the related merger application proceeding at FERC were likewise submitted in support of the pending PUC merger application Subsequent to the Applicants' filing at FERC, Dr. Hieronymus submitted supplemental testimony that modified the Applicants' initial market power mitigation plan.

In order to respond to such testimony, I have reviewed both the initial mitigation plan recommended by Dr. Hieronymus in the FERC and PUC proceedings and his supplemental analysis and additional mitigation recommendations. My testimony in the FERC proceeding addresses the further steps I believe are needed to mitigate the market power in the wholesale market that will result from the proposed merger. I have submitted a copy of that testimony, as Met-Ed/Penelec/Penn Power Exhibit 3-A and Met-Ed/Penelec/Penn Power Exhibit 3-B to my testimony in this proceeding, and incorporate herein my analysis and recommendations.

**Q. Would you summarize those recommendations?**

A. Yes. My testimony at FERC concludes that the proposed PECO-PSE&G merger raises market power concerns for energy, capacity, and possibly also ancillary service. Furthermore, I conclude that the proposed mitigation (under the original restrictions and the relaxed buyer restrictions offered conditionally by the Applicants in their supplemental filing) is unlikely to be sufficient to cure all concerns of market power.

**Q. Please further describe the scope of your review and analysis.**

A. I conducted a thorough review of the analysis and conclusions initially presented on behalf of the Applicants in the Hieronymus testimony and exhibits submitted in this PUC proceeding. I also conducted an independent analysis of the market power potential resulting from the proposed merger. I then evaluated the Applicants' market power mitigation plan in the context of these analyses, and developed additional steps for fact-checking and analysis that I believe are warranted in the context of this proposed merger. Met-Ed/Penelec/Penn Power Exhibit 3-A contains the details of my analysis and recommendations.

Following the Applicants' submission at FERC of supplemental testimony from Dr. Hieronymus addressing additional market power mitigation steps the Applicants are proposing, I conducted a further detailed analysis of that supplemental testimony and submitted further recommendations at FERC. Met-

Ed/Penelec/Penn Power Exhibit 3-B contains my further analysis and recommendations.

**Q. What are the key conclusions from your analyses for the PJM wholesale electricity market and considerations for the competitive retail electricity market in Pennsylvania.**

A. Given the magnitude of the post-merger market power in PJM that will result from this proposed merger, the mitigation plan offered to date by the Applicants is insufficient. The Applicants' combined post-merger market power in the relevant wholesale markets is greater than what was represented by the Applicants, due to shortcomings in Dr. Hieronymus' analysis. The most significant of these shortcomings include: reliance on market price thresholds that are not the most reasonable proxy for expected prices in PJM in 2006; an unrealistic allocation of import transmission capacity; and, a failure to test Applicants' modeling inputs and results against historical data, or otherwise conduct sensitivity analyses of the key assumptions.

Furthermore, the Applicants' mitigation plan fails to identify the specific generation units they will divest, relies on a "virtual" divestiture instead of an actual divestiture of generation, fails to identify the terms and conditions under which long term contracts would be entertained or auctions would be conducted, and fails to identify the extent to which capacity as well as energy would be made available through contracts. In addition, the quantity of capacity and energy being offered as part of the Applicants' mitigation plan, even as revised, is wholly inadequate to redress the potential market power resulting from the proposed merger, especially given the relaxed buyer restrictions conditionally proposed by the Applicants' in their supplemental filing at FERC.

**Q. What recommendations did you include in your testimony at FERC with respect to the proposed merger?**

A. Based on my conclusions regarding the insufficiency of the Applicants' proposed mitigation measures, I recommended that the Applicants increase the amount of generation assets they intend to divest. To the extent that the Applicants undertake these additional divestments, then the market power concerns raised for Pennsylvania retail market as a consequence of the wholesale market may be alleviated.

**Q. Does that complete your direct testimony?**

A. Yes.

## KEY QUALIFICATIONS:

Julia Frayer joined London Economics' Boston office in February 1998. As a Principal at London Economics International LLC, Julia has worked extensively in the US, Canada, Europe, and Asia on various infrastructure related projects, including valuation advisory and negotiations, regulation and market design, and strategic positioning.

As head of the regulatory economics practice at London Economics, Julia is very involved in market power issues. In January 2005, she testified on a FERC Technical Panel on the subject mater of market power testing and mitigation as it relates to FERC's interim screens for generation market power in market-based rate authorization proceedings. She has also prepared the market power analysis for several successful market-based rate applications subsequently to FERC's April 2004 Order modifying the indicative screens for generation market power analysis. Currently, she is advising the Alberta Department of Energy on market power regulation in Alberta after the expiration of the current holding restrictions. As part of this engagement, she has helped designed an innovative ex post test of market prices for evidence of market power rents. She is also advising participants in ERCOT on horizontal market power issues in electricity generation, including market power definition and use of efficient market power testing regimes.

Prior to joining London Economics, Julia was working as an Investment Banker with Merrill Lynch in New York. At Merrill Lynch, she specialized in the financial sector, working closely with specialty finance companies, re-insurance firms, asset management and regional depository institutions, in both mergers and acquisitions aspect and strategic financing areas.

## EDUCATION:

Graduate School of Arts & Sciences, Boston University (1996-97) **M.A.** in Economics
College of Arts & Sciences, Boston University (1994-97) **B.A.**, Summa Cum Laude, in Economics and International Relations, member of Phi Beta Kappa

## EXPERIENCE:

The projects briefly described below are typical of the work Julia has performed throughout her career at London Economics:

- ***Advisory to the Alberta Department of Energy on market power safeguards for the Alberta electricity sector:*** As part of the London Economics team, Julia managed the theoretical analysis and quantitative simulation modeling in the design and testing of recommended new regulatory regime. Analysis and recommendations will be presented to stakeholders in the spring of 2005.

- ***Economic analysis and expert testimony in front of the Public Utilities Commission of Texas on market power related issues:*** prepared and filed testimony and quantitative analysis on questions of market definition and market integration. In 2003, also provided testimony on pricing safeguards proceeding, which looked at alternative market power testing procedures for market power, analyzed implications on investment, and disused efficiency consequences of certain bidding behavior.

- ***Contract analysis and risk management:*** Julia led analysis of large market participants' collar contract positions within its overall portfolio-wide risk management strategy in Northeast market. Analysis and risk management recommendations will be presented to Board of Directors.

- ***Preparation of analysis for generation market power under FERC's indicative screens:*** In support of various acquisitions by major international power companies the Northeast announced in 2004, Julia has prepared and continues to be involved in expert testimony for Market-based Rate Authorization applications, Triennial Reviews, and Section 203 filings.

- ***Market analysis and forecasting for IPP developer in Ontario in response to Ministry of Energy's RFEI for 2,500 MW of clean energy:*** Julia directed the quantitative analysis and wholesale electricity price forecasting completed for an IPP. Projections were used to justify project sponsorship of a small gas-fired plant in front of the IPP's Board of Directors and led to project submission to RFEI. In addition, Julia and her team of economists designed a risk model for the client to evaluate the contract payment risks vis-à-vis actual dispatch.

- ***Resource adequacy workshop:*** Julia co-presented at an IPPSA-sponsored workshop in Alberta on resource adequacy market institutions, specifically speaking to the installed capacity and locational installed capacity markets implement in the US among certain Northeastern ISOs.

- ***Econometric analysis of the elasticity of demand for transmission services between Canadian provinces and US markets in the Northeast:*** Julia led the economic analysis for an IPP investigating the impact on trade from increased transmission costs, involving multi-factor regression analysis of nodal electricity prices, price spreads across markets, and interchange flows (imports and exports) across borders. Analysis will be used as evidence in a regulatory hearing for proposed tariff changes.

- ***Monitoring of 5,500 MW RFP for energy services for standard offer contract issued by Connecticut-based utility:*** the Department of Public Utility Control of Connecticut retained the services of LEI to assist the DPUC in monitoring the power procurement processes for Connecticut Light & Power's (CL&P) Transitional Standard Offer auction in November 2004 for services in 2005 and 2006. Julia led LEI's team in providing advisory services to the DPUC, including guidance on communications protocols, design of sales contract agreement (between CL&P and winning bidders), and also valuation of final bids vis-à-vis the forward market alternatives available to the utility. Julia filed an affidavit after completion of the process which the Commissioners used to approve the process and the contracts between CL&P and the winning bidders.

- ***Economic advisory on market power mitigation tests:*** for a large US-based utility in the Southwestern part of the US, consulting on market design features related to a proposed nodal market, including most significantly the market power analysis framework. LEI proposed strategy and is assisting in the development of an implementation framework for the local market, including prepared reports for the market design team and state commission. In addition, the approach will be proposed for federal review at FERC.

- ***Analysis of LMPs in New England:*** using well-established econometric techniques, analyze location-based marginal prices in New England since inception of the new nodal system. Assess the node-specific marginal loss and congestion premiums for certain assets located in load pockets. Analysis integral to a valuation of a portfolio of generation assets and power supply agreements.

- ***Valuation of a pumped storage facility:*** in support of an asset bid by a multi-national player, Julia and her team of economists and modelers completed a medium-term analysis of potential peak versus off-peak price trends in a key Eastern Interconnect market. The price forecast was based on both network simulations using marginal cost-based bidding and strategic bidding. The strategic biding analysis was based on an innovative algorithm, referred to as ConjectureMod, developed by LEI in consultation with a well-known game theorist in electric power markets.

- ***Extensive economic support of a private client's acquisition of a New England-based generating portfolio:*** as part pf an on-going engagement, Julia is assisting a large Canadian private client in its acquisition of a large New England generation portfolio. Julia and her team supported the client's valuation team, providing extensive forecasting and revenue modeling support for the bid development, due diligence, and cost-benefit analysis of key components of the portfolio (which contains an assortment of power plants, ranging from coal-fired facilities to hydro units, and other power sector-related assets, such as transmission rights contracts, power purchase agreements, and power supply obligations). London Economics, with Julia's support, is currently working on FERC filings in anticipation of the acquisition, which will assess the market power attributes of the transaction, per Section 203 requirements. In addition, London Economics'' quantitative and modeling analysis will be used to support securitization and credit rating efforts which may include the acquired assets.

- ***Development of a methodology for transmission assessment for the CA ISO:*** LEI was engaged by the California Independent System Operator (CA ISO) to construct a framework for the economic valuation of transmission investment. Though grounded in a cost-benefit analysis approach, the methodology is moved beyond traditional valuation frameworks to incorporate concepts from real options investment analysis and game theory, and include innovative techniques for forecasting market power implications for wholesale power markets. In the last phase, LEI demonstrated the practical application of the methodology to a real-world transmission investment. The work, completed jointly with the CAISO, was filed with the CPUC in late 2002. As a result of this work, LEI developed a linear program model, which combined with econometric techniques, which helped resolve and evaluate the question of generation and transmission interdependence.

- ***Support the Balancing Pool on economic issues related to the MAP II sale of dispatch rights associated with key generation assets currently controlled by the Balancing Pool:*** conducted an in-depth analysis of current and future market outcomes under a variety of ownership structures (required multi-year simulation modeling of strategic behavior using CUSTOMBid) for energy and ancillary services market in Alberta, quantitative analysis served as foundation for the design of efficient holding restrictions that would be applied to the sale of the Clover Bar, Sheerness, and Genesee contracts; consulted the Balancing Pool, MAP Committee, and associated parties on sale process and auction design principles; provided an independent valuation of the contracts using an options-based approach based on London Economics' proprietary spark-spread model.

- ***Valuation of international transmission project***: using a real options application involving locational price spreads, designed specifically for this engagement, Julia and her team of economists quantified the congestion rents expected to be earned by the developer of an international transmission line in North America and thus evaluated the private benefits to the transmission owner.; financial model constructed for developer to use in analyzing economics of the project on an on-going basis, in order to win Board approval and negotiate risk-sharing contract terms with co-sponsor.

- ***Preparation of valuation for a successful bid in a generation auction in Ontario:*** Julia assisted in the valuation of the Mississauga hydro portfolio. Economic analysis involved the use of LEI's market power analysis (using London Economics' proprietary game theoretic model of strategic behavior), LEI's production cost-based simulation software, POOLMod, and London Economics' tailored real options-based approach for hydro assets. As part of this engagement, LEI staff participated in the initial round analysis, aided in the due diligence process, and consulted the client on second-round bidding.

- ***Market study of the Southeast US and projection of power purchase options for a 400-MW load facility siting at the cross-roads of several Midwest and Southeast markets (SERC, SPP, MAIN, and MAPP regions):*** in advising a large industrial customer on its power supply options (buy or build) over the medium-term, LEI conducted a joint economic and technical study of the power markets and transmission systems in the Southeast market; Julia coordinated the engineering assessment, involving extensive analysis of the security of the transmission grid through load flow analysis and contingency tests. Economic analysis build upon the transmission topography defined in the technical assessment and provided the client with a medium-term independent outlook on wholesale energy prices for the market, based on regional configuration and realities of the transmission system in this part of the country. LEI's *POOLMod production cost simulation software used to complete* the forecast.

- ***Economic feasibility study of a New York City cogeneration facility, a Western New York peaker, New York City CCGT (various clients)***: for a developer, prepared a ten-year revenue forecast for a proposed cogeneration facility, including a forecast of energy and capacity revenues (namely intrinsic revenues) and a volatility or real options-based adder (extrinsic revenues) for the New York City zone of the NY ISO. Analysis was used in support of board approval and aided in the design of the project (e.g., choice of technology and flexibility of such technology vis-à-vis expected market outcomes). For another private client, conducted a longer term projection (spanning 20 years) for a peaking power generation project in Western New York, producing a forecast for regional energy, installed capacity, options-based adders, and ancillary services revenues streams.

- ***Implementation of real options modeling framework:*** conducted numerous valuation exercises using real options-based framework for generation assets and transmissions rights for a variety of engagements, including asset valuation, and structuring of transmission rights portfolio.

- ***Valuation of Mid-Atlantic utility (private client), 2001:*** co-led economic aspect of valuation process for potential acquisition of Mid-Atlantic utility for international entity. Analysis included valuation of PJM-based generation portfolio through the use of production cost-based models and real options applications. Julia also coordinated evaluation effort for trading entity and regulated asset base (wires assets), including review of exposure due to provider of last resort obligations. Julia and her team of economists assessed contract portfolio and load growth parameters, as well as mitigation measures employed by target utility.

- ***Modeling of the future value of emissions reduction credits in regional, continental and global emissions trading markets:*** on behalf of large multinational client, Julia completed a study of the short to long term dynamics of the emissions trading markets. The majority of the focus was on greenhouse gas emissions and the potential for trade-able instruments in North America based on recent publicized transactions and pilot trading programs. However, discussion of current US emissions trading markets (for nitrogen oxide and sulfur dioxide) and their relative features was included in the report.

- ***Valuation of Ontario generating facilities, including assessment of regional electricity markets:*** organized and implemented major modeling effort to determine potential value of generation stations in Ontario. Assessed impact of transmission constraints and restructuring efforts in neighboring markets on future wholesale market prices; forecast competitive market price for Ontario over the long term with detailed review of market dynamics and key price formation drivers; projected the reaction of key market players and the implications of their actions of market prices over the near term utilizing proprietary game theoretic model.

- ***Measurement of contract exposure under a series of PPA contracts and its effect on enterprise value:*** this study was done in conjunction with a due diligence process, where London Economics was part of team analyzing a potential merger between an international power producer and diversified US utility. In identifying key issues in merger between these two entities, London Economics was given the task of defining and quantifying the liabilities associated with the US utilities' power purchase agreements. Julia lead the analysis on behalf of London Economics in the due diligence process: constructing a theoretical framework and applying it to complex asset swap and power purchase agreements in order to measure the magnitude of the liability via current and forecasted market conditions.

- ***Surveyed the current US environmental regulatory framework for international client and produced detailed compliance cost analysis for US generation asset operators:*** investigated current and future policy guidelines (including stay of OTAG program by Federal Courts), outlined key regulation and emission protocols under EPA's Acid Rain Program, Ozone Transport Regulation and New Source Review, measured the cost of compliance options for US generators through analysis of forecasted allowance prices, and the cost of technological mitigation implementation (BACT) and other emissions reducing initiatives (e.g. coal switching, operational guidelines). As a final product, Julia authored a working paper that laid out the multiple layers of environmental regulation for generators in the US with a detailed case study, defining the technological and cost impacts of this regulation on one large US utility.

- ***Review of market dynamics in the California market as part of generation asset valuation:*** London Economics was hired by leading financial institutions to review the long term energy, ancillary services, and capacity price forecasts for Southern California and resulting revenues for a set of assets that were undergoing debt financing. As part of this investigation, Julia drafted a critique of the proposed price forecast and suggested methodology improvements and a set of alternative price benchmarks for debt financing valuation purposes.

- ***Valuation of distribution assets:*** quantified synergies and developed strategies for potential cross-border transaction between top Canadian distribution corporation and affiliate of Top 20 US utility, by performing in-depth analysis of diversified strategies available to global energy companies in energy generation, transmission, distribution, wholesale and retail marketing, energy services, and other infrastructure industries. Julia co-managed a team of economists and consultants, pursuing unique valuation approaches in this transaction, utilizing comparable analysis, examination of PRB mechanisms and other regulatory pricing designs, growth strategies, as well as the application of real options theory.

- ***Midwest price forecasting:*** Julia headed the analysis of long-term price forecasts for the Midwest US (ECAR, MAIN, and MAPP); managing a team of economists in their effort to establish fifteen-year energy and capacity price forecasts for several US regions. As part of the modeling effort, London Economics proprietary dispatch simulation model, POOLMOd, was used, in conjunction with a competitive capacity-pricing module. The long-term modeling effort required detailed investigation of the micro and macro-economic issues facing these regional markets: demand profiling, growth forecasting, reserve margin and new entry activity assessment. This analysis was used by a client in establishing market values for assets they have targeted to acquire over the medium-term.

- ***Completed initial modeling and organized competitive market analysis tutorial for the staff of the Italian Energy Regulatory Authority:*** worked with the regulatory advisors to the Italian government in their on-going effort to restructure the power sector in Italy. Julia, as part of an international team of economists consulting the regulator, led the competitive market modeling tutorial. She advised IERA staff on the use of London Economics' proprietary pool simulation model in assessing the current issues in the Italian generation market (such as potential market power problems) and market conditions after privatization/divestiture.

- ***Valuation of coal-fired generation assets in the NYPP:*** forecast energy and capacity prices for the New York market on a sub-regional basis, rooted in transmission constraint parameters. Utilizing London Economics' proprietary pool simulation model, Julia composed detailed unit-by-unit performance, revenue and cost parameters over the next twenty years. In addition, she investigated the affect on market projections by varying key drivers and scenario assumptions, in an effort to bracket the perceived risks to clients. Julia studied the influence of several key market drivers, such as the implementation of various environmental programs, changes to system supply-demand profile due to various new entry/retirement profiles, modification of market rules, and shifts in key input markets (e.g. coal, natural gas and oil markets).

- ***Valuation of New England, PJM and Midwest generation assets:*** evaluated potential value of assets available under various regional auctions for a dominant IPP player. Julia worked with client in composing a bid proposal by assessing market risks posed by various factors, such as fuel price shifts, merchant plant construction scenarios, site conversion potential, and transmission constraints and through extensive production cost modeling.

## PUBLICATIONS AND SPEAKING ENGAGEMENTS:

Frayer, Julia "Written Statement of Julia Frayer for the January 27th 2005 Technical Conference in Docket RM04-7-000" Panelist, *FERC Technical Conference*, Washington D.C., January 27, 205.

Frayer, Julia "Competitive procurement options for Ontario's LDCs" Speaker, *APPrO 2004 Conference*, Toronto, Ontario (Canada), November 24, 2004.

Frayer, Julia, Nazli Uludere, and Sam Lovick "Beyond market shares and cost plus pricing: designing a horizontal market power mitigation framework for today's electricity markets." *Electricity Journal,* November 2004.

Frayer, Julia "The World Changed on August 14th: the (Second) Great Northeast blackout." Chairman of Panel Session, *Electric Power Conference* 2004, Baltimore, Maryland, March 30, 2004.

Frayer, Julia "Alternative to LMP pricing for transmission: a case study of the ICRP approach used by National Grid Company in the UK." Speaker, *Electric Power Conference* 2004, Baltimore, Maryland, March 31, 2004.

Frayer, Julia "Big ticket leasing - what next for the future?" Panelist, *Big Ticket Leasing 2003,* London (United Kingdom), March 12, 2003.

Frayer, Julia "Evaluating the Electron Highway" Speaker, *IPPSO 2001 Conference,* Richmond Hill, Ontario (Canada), November 28, 2001.

Frayer, Julia and Nazli Uludere "What is it worth? Application of real options theory to the valuation of generation assets" *Electricity Journal,* November 2001.

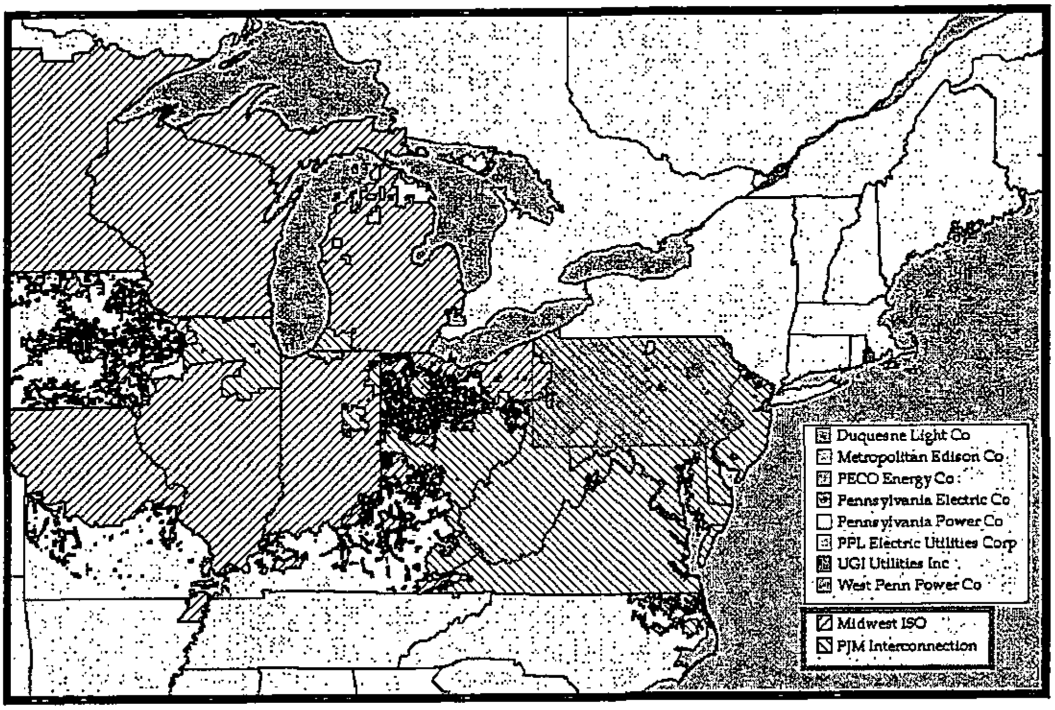
Goulding, A.J., Julia Frayer, Jeffrey Waller "*X Marks the Spot*: How UK Utilities Have Fared Under Performance-Based Ratemaking" *Public Utilities Fortnightly,* July 15, 2001.

Frayer, Julia "How much is it worth? Applying real options valuation framework to generation assets" Speaker, *Electric Power 2001*, Baltimore, Maryland, March 22, 2001.

Goulding, A.J., Julia Frayer, Nazli Z. Uludere "Dancing with Goliath: Prospects After the Breakup of Ontario Hydro" *Public Utilities Fortnightly*, March 1, 2001.

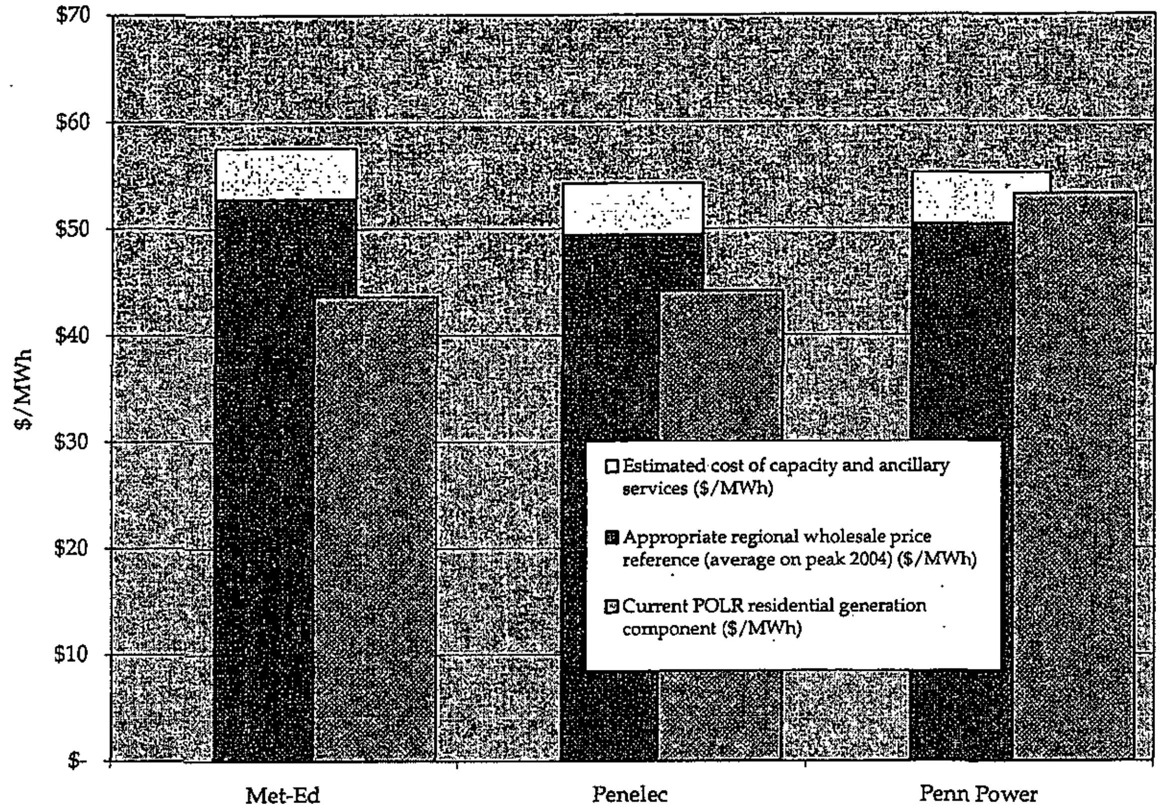
Frayer, Julia and William Chapman "Improving price forecasting in wholesale power markets through the application of models of strategic bidding" Speaker, *EPRI International Pricing Conference 2000*, Washington, D.C., July 28, 2000.

**Map of Pennsylvania with distribution company service territories and demarcation of the PJM and MISO footprint**




All of Pennsylvania is part of the PJM RTO, except the small region in western Pennsylvania, which is part of MISO.

**Comparison of generation rate cap for residential POLR customers to recent average on-peak wholesale electricity prices and ICAP and ancillary services costs for the Companies**




*Note that POLR generation component levels are based on the tariffs currently in place, while regional wholesale prices are based on actual observed on-peak prices for 2004. We use on-peak prices as the wholesale references since residential customers consume mainly during on-peak hours; as such, use of a 7x24 average price would not be appropriate. The wholesale price index used to proxy wholesale electricity for Penn Power was PJM West. Estimated costs for capacity credits and ancillary service are derived from PJM historic data.*

*Source: utility rate filings, Bloomberg, PJM, and London Economics' estimates*

Met-Ed/Penelec/Penn Power Statement No. 3
EXHIBIT 3-A

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

RE: JOINT APPLICATION OF PECO ENERGY COMPANY
AND PUBLIC SERVICE ELECTRIC AND GAS
FOR APPROVAL OF THE MERGER OF
PUBLIC ENTERPRISE GROUP INCORPORATED
WITH AND INTO EXELON CORPORATION

DOCKET NO. A- 110550F0160

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

| | | |
|---|---|---|
| **Exelon Corporation** | ) | **Docket No. EC05-43-000** |
| | ) | |
| **Public Service Enterprise Group Incorporated** | ) | |

PREPARED TESTIMONY OF JULIA FRAYER

ON BEHALF OF FIRSTENERGY SERVICE COMPANY


London Economics International LLC
717 Atlantic Ave, Unit 1A
Boston, MA 02111
www.londoneconomics.com

# Table of Contents

## Table of Exhibits

# 1 Introduction

**Please state your name and business address.**

My name is Julia Frayer, and I am one of the partners and a Managing Director of London Economics International LLC ("LEI"). My business address is 717 Atlantic Avenue, Unit 1A, Boston, MA 02111.

**What is the purpose of your testimony?**

I have been engaged by FirstEnergy Service Company ("FirstEnergy") to review the economic and market power-related analysis prepared by Exelon Corporation ("Exelon") and Public Service Enterprise Group Incorporated ("PSEG"), who are jointly referred to as the "Applicants," in their *Application for Authorization of Disposition of Jurisdictional Assets Under Section 203 of the Federal Power Act*, dated February 4th, 2005.

My engagement included three phases of evaluation. First, I reviewed the analysis and conclusions presented by the Applicants, including the assumptions and methodologies used, and conclusions reached by the Applicants' technical witness, William H. Hieronymus, in the Competitive Analysis Screen he completed per the guidelines set out in Appendix A to the Federal Energy Regulatory Commission's *Merger Policy Statement* ("Order No. 592").[1] Given the significant combination of generation assets expected as a result of this merger, I specifically

[1] Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement, Order No. 592, FERC Stats. and Regs. 31,044 (1996), reh'g denied, Order No. 592-A, 79 FERC 61,321 (1997) ("Merger Policy Statement"); Revised Filing Requirements Under Part 33 of the Commission's Regulations, Order No. 642, FERC Stats. & Regs. 31,111 (2000), order on reh'g, Order No. 642-A, 94 FERC 61,289 (2001) (collectively Order No. 642).

focused on the horizontal market power implications, as evidenced by the application of the Delivered Price Test. Next, I modified key assumptions underpinning the horizontal market power analysis based on current market expectations and alternative, well-justified considerations, and assessed the impact of these changes on the conclusions reached by the Applicants and Dr. Hieronymus. I then conducted an independent Competitive Analysis Screen and Delivered Price Test using the generation data provided by the Applicants and Dr. Hieronymus, in conjunction with my assumptions on other key factors. I also conducted an independent analysis of the Applicants' market power potential using alternative methods and quantitative techniques. Unsurprisingly, the proposed merger creates large anti-competitive effects, which require mitigation. Therefore, lastly, I evaluated the robustness of the Applicants' proposed mitigation plan, based on the above set of independent analyses.

**Please summarize your relevant professional background.**

As Managing Director of LEI, I currently direct many of the company's engagements involving market power analyses, strategic bidding and simulation modeling, and market design with respect to market power issues and regulation. I have consulted with many clients on the implications of the Federal Energy Regulatory Commission's ("FERC" or the "Commission") merger guidelines with respect to their strategic business decisions, and worked with system operators, regulators, and state commissions on analyzing market power behavior and measuring its impact on deregulated electricity markets. I have prepared market power analysis and testimony for proposed acquisitions under Section 203 of the Federal Power Act ("FPA"), as well as generation market power analyses for a number of market-based rate applications under Section 205 of the FPA, per the revised interim guidelines established in the

FERC's *AEP Power Marketing, Inc.* Order.[2] In January 2005, I testified on FERC's Technical Panel on the interim generation market power screens for market-based rate authorizations. I have also recently presented testimony on pricing safeguards and market power issues in front of the Public Utility Commission of Texas, and designed market power identification and amelioration mechanisms for the Department of Energy of Alberta. For further details, I have attached my resume in Exhibit 1.

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[2] *AEP Power Marketing, Inc., et al., Order on Rehearing and Modifying Interim Generation Market Power Analysis and Mitigation Policy,* 107 FERC ¶61,018 (April 14, 2004) ("April 14th Order"), Order on Rehearing, 108 FERC ¶61,026 (July 8, 2004) ("July 8th Order").

## 2 Executive summary

**In your professional opinion, does the merger raise competitive concerns?**

Without question, the proposed merger will increase the concentration of the PJM wholesale generation market and key sub-markets for energy, capacity and ancillary services within PJM. I have completed an independent analysis of the merger's impact on the generation market using the Commission's Competitive Analysis Screen. The Herfindahl-Hirschmann Index ("HHI")[3] levels after the merger and the change in HHI levels caused by the merger are substantially higher than the thresholds established by the Federal Trade Commission and Department of Justice's *Horizontal Merger Guidelines*[4] and adopted by the FERC in the *Merger Policy Statement.*

**How does your Competitive Analysis Screen compare to the analysis conducted by the Applicants?**

I have developed assumptions for my independent analysis based on the latest market information. The changes in assumptions increase 14 of the 30 HHI levels tested under the Delivered Price Test post merger and increase the change in HHIs as well. I further conducted a sensitivity analysis off the baseline HHI estimates to test the robustness of the conclusions to a

---

[3] The HHI is the sum of the squares of the individual market shares of market participants (each multiplied by 100). The HHI score can therefore range from close to 0 to 10,000. A true monopoly (a single supplier) would have a score of 10,000. The theoretical corollary supporting the validity of the concentration analysis in the HHI can be found in Cournot market theory, which demonstrates and how firms will react to each in an oligopolies if they are competing on quantity terms, and what the resulting equilibrium price outcomes would be vis-à-vis prefect competition. The HHI is significant in this context because it yields the price-cost margins that are consistent with Cournot competition. *The New Palgrave Dictionary of Economics (1987).*

[4] U.S. Department of Justice and Federal Trade Commission, Horizontal Merger Guidelines § 0.1 (April 2, 1992) ("Horizontal Merger Guidelines").

variety of market price conditions.

Based on my preliminary analysis, additional mitigation amounts are required above and beyond the 5,500 MW earmarked by the Applicants across all three geographical market dimensions. Even after adjusting the Economic Capacity for the Applicants' proposed mitigation, I had:

- HHIs as high as 1,663, with an HHI change as high as 128 in Expanded PJM;
- HHIs as high as 1,535, with an HHI change as high as 126 in Pre-2004 PJM; and
- HHIs as high as 1,596, with an HHI change as high as 187 in PJM East.

My independent analysis of Economic Capacity suggests that an additional 390 MW of mid-merit divestitures is needed in the PJM East market, to cure failures in the HHI screens, above and beyond the 5,500 MW proposed by the Applicants, summing to a total mitigation amount of 5,690 for this case and geographic region. However, for the Expanded PJM market, an additional 890 MW of divestitures is needed on top of the 5,500 MW already allocated by the Applicants for a total of 6,390 MW.

The need for additional mitigation is further supported by the sensitivity analysis I conducted on Destination Market Prices. The sensitivity analysis indicates that when the price thresholds are increased by 25%, 10 of the 30 HHI post merger levels tested under the baseline Delivered Price Test increase. Similarly, when we look at the sensitivity analysis where the price thresholds have been decreased by 25%, 11 of the 30 HHI levels increase along with an increase in the HHI changes resulting from the merger. The 25% increase scenario also suffers from extensive baseload and mid-merit screen failures for PJM East. An additional 960 MW of mitigation would be necessary under such high market price conditions in order to alleviate horizontal market concerns in PJM East, for a total divestiture amount of 6,260 MW under this scenario.

**What other market power analysis did you complete?**

In addition to the Delivered Price Test discussed above for the energy market, I performed a number of other quantitative examinations of market power in the electricity generation sector. For example, I completed a market share screen for the Applicants post-merger using the FERC's approved methodologies for assessing generation market power under Section 205 of the FPA. The Applicants will need to do this analysis when they seek market-based rate authority. Though the market share screen is not an explicit market power test under Appendix A of the *Merger Policy Statement*, the concept of market-based authority and the impact of such authority on market power is explicitly referred to in the *Merger Policy Statement*. Thus, the results of this market share screen test are noteworthy and applicable by extension.

Based on the methodologies discussed in the April 14th Order, and using the Applicants' generation figures, PJM's simultaneous import capacity, and historical demand data for 2004, the market shares for the Applicants after the merger exceed the 20% market share threshold in all seasons, even after the proposed 5,500 MW of divestitures are deducted from the Applicants' capacity and after accounting for the Applicants' long-term obligations. An additional 3,000 MW of capacity - above and beyond the Applicants' proposed 5,500 MW of mitigation - needs to be divested or put under firm commitments in order to bring the Applicants in compliance with the Market Share Screen. In practice, market-based rate considerations are not easily separable from the merger approval process, especially in light of the need for mitigation. I thus recommend that the FERC consider Section 205 remedies in the context of this merger analysis.

In addition to the Delivered Price Test and market share analysis, I evaluated the extent of market concentration among available generators competing to serve the next increment of demand (I refer to this as the Concentration Test of Spare Capacity). The results of this analysis lent further support to my broad conclusions regarding the presence of market power potential and the need for extensive mitigation.

I explored the prospects of using historical price and bid data in the future to corroborate the Competitive Analysis Screen conclusions. PJM releases actual bid data for all market transactions with a six-month delay; thus, there is a wealth of data available for further analysis. Though detailed analysis of historical bid data was outside the timeframe allotted under the February 10, 2005 *Notice of Filing*, I did conclude that the historical bid data could be usefully implemented in additional analysis. In fact, I was disappointed not to see historical transaction data as part of the Applicants' filing, especially as the Competitive Analysis Screen specifically insists on such data.

I also applied an HHI-based market concentration analysis to PJM's Capacity Credit market. The results of my analysis suggest that there will be screen failures as a result of the merger under a range of possible market evolutions. Moreover, the screen failures in my UCAP-adjusted analysis are not sufficiently cured by the mitigation measures proposed by the Applicants. For example, even after incorporating Dr. Hieronymus' proposed mitigation amounts (5,300 MW of ICAP divestiture for PJM East and 2,300 MW of ICAP divestiture for Expanded PJM), I estimated:

- HHIs as high as 1,114, with an HHI change as high as 210 in Expanded PJM; and
- HHIs as high as 1,621, with an HHI change as high as 137 in PJM East.

Depending on the assumptions one makes on allocation of external capacity, the Applicants need to divest capacity rights in the range of 5,385 MW to over 5,620 MW in PJM East and 4,200 MW to over 7,550 MW for the Expanded PJM market area in order to cure the PJM Capacity Credit market screen failures. These figures are greater than the mitigation requirements determined by Dr. Hieronymus. In fact, the high end of my mitigation amount for Expanded PJM is over two times the amount Dr. Hieronymus estimated in his analysis for this market area. The difference is the result of the UCAP adjustment, which Dr. Hieronymus did not undertake, and a more pragmatic allocation assumption for external resources.

**What conclusions did you reach on the basis of these other quantitative analyses?**

Though concentration ratios may be helpful in screening for the need for further analysis, they should not be relied upon as a definitive test for the sufficiency of mitigation to meet market power concerns, unless sensitivity analyses and other assessments confirm the overall robustness of the screen results.

My independent analysis under different, but equally plausible and justifiable market conditions, suggests that the market power potential of the Applicants post merger may be worse - and in some instances, far worse - than what has been presented by Dr. Hieronymus.

I strongly believe that the FERC should direct that this merger proceeding be set for hearing and require the Applicants to provide additional information and perform further analyses before deciding on the nature and extent of the mitigation necessary to assure that the proposed merger will be consistent with the public interest.

**Are the Applicants' proposed mitigation measures sufficient to cure the potential harm to competition resulting from the merger?**

*My analysis suggests that the proposed mitigation measures are insufficient to protect* against the Applicants' market power. Much of the analysis I completed expands on the focus espoused by Dr. Hieronymus, who evaluated the merger and designed the proposed mitigation requirements while narrowly focusing on the Delivered Price Test. Given the far-reaching size of this merger, I believe a more in-depth analysis of market power issues, with extensive sensitivities, should have been conducted by the Applicants. The FERC needs to ask itself, has market power potential been thoroughly examined and carefully measured taking into consideration all possible future market conditions?

I believe the answer to the above question is "No." Alternative, reasonable, and well-justified assumptions for the same Competitive Analysis Screen, as well other analytical methodologies, suggest that the Applicants' potential for market power is significantly larger. Based on my analysis of Economic Capacity, additional mitigation for the energy market of as much as 900 MW may be necessary for the mid-merit category of assets. This would signify a total mitigated quantity of nearly 6,500 MW for the Expanded PJM market. Capacity market problems may require even larger-scale mitigation protocols under certain conditions, as I noted above and discuss further below.

**Do you have any further recommendations to improve the proposed mitigation plan?**

The Applicants need to identify the plants they will divest, as capacity is not interchangeable due to technical differences in operation, physical location (in the nodal market), virtual location (on the 'supply' curve), and price-setting capacities.

The Applicants have also failed to provide historical transaction data as part of the record for this merger proceeding to substantiate their conclusions on market power potential and the sufficiency of their proposed mitigation plan.

In addition, there is a substantial amount of ambiguity surrounding the proposed mitigation plan. For example, some of the interim mitigation measures may not be substantial enough to dispel the expectations of market participants regarding the market power abilities of the Applicants and thus will not provide the safeguards that the FERC would want to see implemented. In addition, the Applicants have not provided enough detail on the contingency plans in case auction processes are not successful or defaults occur in the future which cancel out the long-term commitments and return control over output back to the Applicants. Such uncertainties need to be addressed and resolved in order to ensure that the final mitigation measures efficiently achieve their intended goals.

# 3 Overview of the proposed Exelon-PSEG merger

**Please describe briefly the proposed merger.**

In December 2004, Exelon announced the acquisition of PSEG. Both Exelon and PSEG own generation assets, as well as electricity transmission and distribution assets. In addition, both companies have affiliated local gas distribution companies. The merger would create a company with a 51,584 MW portfolio of U.S. generation assets according to the Applicants' own figures,[5] with 40,000 MW within the boundaries of the PJM-operated market. Relative to the PJM market where the majority of the combined entities' assets are situated, they would be the largest generator by far. This is highlighted in Exhibit 2, which presents the total capacity for each of the top ten suppliers in each of the three geographical markets analyzed by the Applicants.

In fact, the Applicants will own over 66% of the nuclear capacity in the Expanded PJM market and 100% within PJM East, as documented in Exhibit 3. The Applicants will also own (and control prior to mitigation) over 5% of all coal capacity, and 28% of peaking gas- and oil-fired capacity in Expanded PJM and over 40% of all coal capacity, and over 56% of peaking gas-fired capacity in PJM East.

[5] *Presentation from December 20th 2004 Press Conference.* See http://www.exeloncorp.com/corporate/about/a_merger.shtml

**Please describe the market power analysis presented by the Applicants.**

The Competitive Analysis Screen conducted by Dr. Hieronymus concludes that the merger would result in many segments of the wholesale generation market being moderately or highly concentrated with post-merger Economic Capacity HHIs in some instances as high as 2,390 (with changes in HHI of over 1,000) and a market share for the Applicants of over 46%.[6] According to the Department of Justice, "Where the post-merger HHI exceeds 1,800, it will be presumed that mergers producing an increase in the HHI of more than 100 points are likely to create or enhance market power or facilitate its exercise."[7] This same set of thresholds has been accepted by the Commission in Order 592. Given these cutoff points, the Applicants (pre-mitigation) fail the Competitive Analysis Screen in every product segment and season, and in all three geographical market dimensions. Exhibit 4 summarizes the HHI levels estimated by Dr. Hieronymus for post-merger economic capacity across the various segments of the market under his application of the Delivered Price Test.

**Please describe the proposed market power mitigation plan presented by the Applicants.**

The Applicants have offered to divest 2,900 MW of peaking and mi-merit plant in PJM East and enter into firm, energy-only contracts for the output from 2,600 MW of nuclear capacity, which is referred to as "virtual divestiture." Coupled with certain bidding restrictions in PJM's Capacity Credit market, the Applicants contend that the above divestiture amounts are sufficient to cure all screen failures. Thus, no additional divestitures have been proposed by the

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[6] *Application, Exhibit J-7.*

[7] U.S. Department of Justice and Federal Trade Commission, Horizontal Merger Guidelines § 0.1 (April 2, 1992) ("Horizontal Merger Guidelines").

Applicants for installed capacity and ancillary services. The Applicants also claim that there are no vertical market power concerns with the proposed merger and thus mitigation in that respect is unnecessary.

# 4 Assessment of market power analysis

**What is market power and how does it relate to electricity markets?**

The classic definition of market power is *"the ability to profitably maintain prices above competitive levels for a significant period of time."*[8] Practitioners also make a distinction between vertical versus horizontal market power. Vertical market power is market power between different segments of the value chain, for example, between transmission and generation business areas. Horizontal market power, on the other hand, is market power within a segment, such as the wholesale generation market or the retail electricity market. In the context of generation markets, a firm has horizontal market power if it can sustainably increase profits by raising its bids or by withdrawing capacity from the market in order to raise market-clearing prices.

**How is market power taken into account in the FERC's Merger Policy Statement?**

Section 203 of the FPA requires FERC approval for the transfer of facilities subject to the FERC's jurisdiction with a value in excess of $50,000. Under Section 203, applicants must demonstrate that the transaction is consistent with the public interest and that it will not adversely affect: (1) competition in the relevant markets; (2) wholesale rates; or (3) the ability of the FERC to effectively regulate the applicants.

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[8] U.S. Department of Justice and Federal Trade Commission, Horizontal Merger Guidelines § 0.1 (April 2, 1992) ("Horizontal Merger Guidelines").

When evaluating the competitive market impact of an asset sale on electricity generation markets, the FERC has generally adopted the US Department of Justice and Federal Trade Commission's *Horizontal Merger Guidelines,* as described in Appendix A to FERC's *Merger Policy Statement.* The *Horizontal Merger Guidelines* and *Merger Policy Statement* sets out five steps for such an analysis. The first stage is to assess whether the merger would increase concentration in the market. The second stage determines whether the merger would result in "adverse competitive effects." The third stage looks at whether new entry into the market could mitigate any negative impacts from the merger, while the fourth stage assesses whether or not the merger would result in efficiency gains that are not achievable in any other way. Finally, the fifth and last stage of analysis recommended by the *Horizontal Merger Guidelines* assesses the likelihood in the *absence* of the merger that either party would fail and thereby cause its assets to exit the market.

The primary focus of my analysis is on the horizontal market power analysis of the proposed merger addressed in the first two stages of analysis under the *Merger Policy Statement* and the first item under review according to Section 203 of the FPA.

## 4.1 Overview of Horizontal Market Power

**In what context have you examined horizontal market power?**

Horizontal market power issues in this merger proceeding are related to the wholesale electricity market, where generators compete to produce and sell units of energy, typically measured in MW (or MWh) terms, as well as other ancillary services and products, such as capacity. Given the asset ownerships of the merging parties, the focus of the Horizontal Market

Power analysis should primarily be the PJM market area, as there is relatively limited overlap, if any, of Exelon- and PSEG-owned capacity in other markets under FERC jurisdiction. Thus, my analysis has focused on the PJM markets.

**Please describe the PJM wholesale generation market.**

PJM operates a centrally dispatched, competitive wholesale electricity market comprising generating capacity of approximately 144,000 MW and about 330 market buyers, sellers and traders of electricity in a region including more than 45.3 million people in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. PJM grew substantially in 2004 as the result of the integration of American Electric Power Company, Dayton Power and Light Company, Duquesne Light Company and Exelon. Additional expansions are anticipated this year, with the accession of the Dominion Electric Company (Virginia Power).[9]

PJM has since grown to include numerous states to the West and South of the original group of PJM members and serves an approximate peak demand of 115,000 MW.[10] The service territory of the PJM market, after the Dominion Electric Company's accession into PJM is complete, is illustrated in Exhibit 5. This is equivalent to the Expanded PJM market definition used by the Applicants, and referenced in our analysis. In addition to operating and

[9] Dominion Electric Company applied to join PJM and form PJM South in June 2003, and is currently undergoing market trials. At this time, Dominion Electric Company's accession into the PJM market is scheduled for later in 2005; thus, it is reasonable to include it in the competitive analysis of the PJM market in 2006.

[10] http://www.pjm.com/about/glance.html

maintaining the transmission network within the market, and interfacing with neighboring system controllers, PJM also operates the Day-Ahead Energy Market, the Real-Time Energy Market, the Daily Capacity Credit market, the Interval, Monthly and Multi-monthly Capacity Credit markets, the Regulation Market, the Spinning Reserve Market, and the Annual and Monthly Auction Markets in Financial Transmission Rights. Suppliers and buyers may also choose to transact in the bilateral markets.

**How does the PJM energy market work?**

The energy market operates on a two-settlement system, with day-ahead and real-time trading segments. Both segments are financially binding. Generators submit offers to supply energy to load. PJM determines a settlement or market-clearing price based on its nodal pricing algorithm, which determines the cost of re-dispatch to meet the next increment of demand at each specific node in the system. Generators receive a location-based market-clearing price, which incorporates the price of energy plus local transmission congestion costs. Load pays a zonal price for electricity, based on a weighted average of the nodal prices.

Despite the complex nature of the nodal pricing algorithm, PJM effectively operates under a single price auction structure. If there is no congestion in a particular period, there will be a single market-clearing price for all nodes and all generators in that period. The generator whose bid is used to clear the market is classified as "marginal" or "price-setting" unit. All other generators that are selected to operate are considered "infra-marginal" - though they do not get to set the price, they get the benefit of the market-clearing price determined by the "marginal" bid.

**What other markets are supported by PJM?**

In addition to the day-ahead and real-time energy markets, PJM procures certain ancillary services, such as spinning reserves and regulation, on a market basis. PJM also administers a capacity credit market to facilitate Load Serving Entities ("LSEs") in fulfilling their Unforced Capacity ("UCAP") obligations. Lastly, PJM also operates a market for Firm Transmission Rights ("FTRs"), which allows participants to financially hedge congestion costs along specific paths in the PJM system. I will speak further about these other markets later in my testimony.

**What markets were covered in your analysis?**

I have specifically evaluated horizontal market power in the energy market and the Capacity Credit market. In addition, I analyzed the Applicants' considerations of horizontal market power in the ancillary services markets.

**What methodologies did you apply in your analysis?**

I applied the methodologies outlined in FERC's *Merger Policy Statement*. In addition, I also applied other FERC-approved tests for market power in the generation sector and well-accepted quantitative and modeling techniques. I will describe each of the approaches I have taken later in my testimony.

### 4.2 Horizontal market power in the energy market

**How does the Commission evaluate the potential for horizontal market power in the energy market?**

The FERC provides the analytical framework and guidelines to quantify the market power potential of the Applicants in Appendix A to the *Merger Policy Statement*. This is known as the Competitive Analysis Screen. The first step of the Competitive Analysis Screen, as with any market power analysis, requires specification of a market definition. Consistent with Department of Justice practice, market definition is addressed for product and geographic dimension. The FERC has typically looked at energy on a seasonal and load-segmented basis, and has traditionally accepted a default geographic market definition of a control area or the boundaries of an ISO or RTO for the "Destination Market." However, applicants and other parties to the proceeding can suggest alternatives geographic market dimensions. Imports into the Destination Market are also taken into account based on available and total transmission capacity from external sources. These assumptions on product and geographic market definition are then combined into an economic and technical deliverability analysis to determine the full spectrum of potential suppliers that can serve demand in the Destination Market at or below 105% of the Destination Market Price.

Once all the suppliers that can physically and economically deliver into the Destination Market are identified, each supplier's own market share is calculated. In turn, these market shares are used to estimate an HHI. The merger is then analyzed in terms of overall market concentration after the merger and the change in HHI attributable to the merger. This is known as the Delivered Price Test.

**What are the relevant HHI thresholds to consider in judging the impact of the proposed merger on competition?**

The FERC, consistent with the Department of Justice's *Horizontal Merger Guidelines,* defines a merger to be free of anti-competitive effects if the post-merger HHI threshold is less than 1,000, as that suggests an unconcentrated post-merger market. If the HHI is between 1,000 and 1,800 and the change in HHI exceeds 100, then it is a moderately concentrated post-merger market and there are some possible harmful competitive effects. If the HHI exceeds 1,800, then it is a highly concentrated post-merger market. Under such conditions, a change in HHI of more than 50 suggests possible anti-competitive concerns, whereas a change in HHI that exceeds 100 generally indicates that the merger is likely to create or enhance market power.

**What measures will be discussed in your analysis?**

There are various measures which the Commission looks at when considering the HHI analysis. Economic Capacity is that capacity which can compete with other resources at the specified Destination Market Price. In other words, Economic Capacity includes all potential generating capacity in a selected market that can deliver energy at a dispatch cost of no more than 5% above the competitive prices, which are referred to as the "Destination Market Price."

I have completed my independent Competitive Analysis Screen using Economic Capacity. The *Merger Policy Statement* also requires review of Available Economic Capacity, which is the actual capacity available to the generating units to sell in the market after fulfilling their native load and other long-term contractual commitments. Available Economic Capacity is intended to reflect the quantity of capacity over which a firm has actual control or that which it can profitably use to make strategic bidding decisions. Data for such an analysis is difficult to obtain, given that extensive contract information is necessary not only for the Applicants' portfolio of assets, but also for every other supplier competing to reach the Destination Market. Given the potential for misleading results if consistent data is unavailable for all generators, I have decided to focus solely on Economic Capacity as a measure of generation (horizontal) market power potential under the Delivered Price Test. This is consistent with the perceived focus of Dr. Hieronymus' FERC testimony, as well as that of Mr. Rodney Frame (who filed testimony on market power related issues on behalf of the Applicants with the New Jersey Board of Public Utilities). Both of the Applicants' technical witnesses concurred on the impracticality of the Available Economics capacity measure.[11]

***Please briefly describe the Competitive Analysis Screen you have undertaken with respect to horizontal market power for energy.***

I conducted an independent assessment of the Delivered Price Test using Dr. Hieronymus' generation database, adjusted for a number of key parameters, such as the Destination Market Prices for the defined products, the quantity of new entry and retirement of generation, forced outage rate assumptions, and the projected dispatch costs of generators in 2006. My assumptions are based on the latest market data available and projected market fundamentals for calendar year 2006, which is consistent with the time horizon by which the Applicants plan to consummate the merger and in-line with the time dimension practitioners use in conducting the Delivered Price Test.

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[11] For example, see pg. 51 of Dr. Hieronymus' testimony (Application, Exhibit J-1 at 51): "The HHIs in both these analyses are somewhat suspect... Available Economic Capacity is a questionable metric for defining market share in PJM..."

Lastly, though I used the same assumptions on import transfer capacity (e.g., 7,500 MW simultaneous import capability published by PJM for the Expanded PJM region) and an allocation approach similar to Dr. Hieronymus' pro rata "squeeze down" approach, I analyzed a wider circle of external markets. Dr. Hieronymus states in his testimony that he evaluated MISO and NYISO only.[12] When analyzing the external market capacity and considering the allocation of such resources to the simultaneous import capability, I have included in my analysis economic capacity from all first-tier markets to PJM, such NYISO, MISO, but also generation from the SERC-based control areas of the Tennessee Valley Authority, Duke Power Company, and Carolina Light & Power Company. I believe that it is important to include these other market areas so as to remain consistent with the spirit of the simultaneous import capability study and the 7,500 MW input assumption on simultaneous transfers into PJM from adjacent regions. PJM has noted that the following "source areas" are "used to supply energy for the PJM import simulation: New York, New England, and Ontario in NPCC, all ECAR companies external to PJM, all SERC companies external to PJM, the MAIN companies external to PJM, and eastern MAAP companies."[13]

Based on the above parameters, HHI estimates were derived for pre-merger, post-merger, and post-mitigation scenarios. In the post-mitigation scenarios, I retained the proposed mitigation measures of the Applicants for comparative purposes and then investigated what, if

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[12] Application, Exhibit J-4 at 2. However, his generation database incorporates data entries for units in SERC and other more distant control areas.

[13] See http://www.pjm.com/markets/market-integration/downloads/documentation/20040909-simultaneous-pjm-import-capability.pdf.

any, additional mitigation would be required to cure screen failures under my independent analysis.

In addition to the baseline estimates, I conducted extensive sensitivity analysis of the Delivered Price Test against a range of Destination Market Prices, in order to gauge the robustness of my conclusions and recommended mitigation measures to changing market price conditions.

**How did you determine Destination Market Prices for the Delivered Price Test?**

The Destination Market Prices that I use in my independent analysis are based on my estimates for projected prices in the relevant geographic markets, taking into account the load levels to be analyzed for the various segments of the market and seasons.

I began my analysis of Destination Market Prices by conducting an econometric price study of 2004 hourly PJM electricity prices. Since my analysis involved three geographical market dimensions, I accordingly studied historical prices that aligned with those geographical dimensions. I also categorized the price data based on month, time of day, and weekday, so that I could differentiate between peak and off-peak periods across the three seasons. Based on the current industry definition of peak and off-peak, I categorized all weekend hours and those between 10 PM and 7 AM as off-peak. The remaining hours for the weekdays were considered on-peak. The seasonal classification was consistent with the well-accepted industry approach, whereby the summer months are June through August, winter is defined to be December through February and the shoulder period consists of all remaining months. Moreover, the seasonal selection was well correlated with the typical hourly profile of observed prices. As an example, Exhibit 6 presents graphs of average hourly prices for each season for the Eastern PJM Hub in 2004.

I also evaluated spot gas prices over the same timeframe. In addition to looking at the absolute price levels for gas and electricity, I analyzed the implied heat rates, which can be calculated by taking the electricity price and dividing by the spot gas price. This was an important aspect of my study as it allowed me to adjust historical electricity prices for 2006 expected gas price trends (based on current NYMEX futures prices for Henry Hub gas) and thus use a reasonable forecast price in my determination of Destination Market Prices.

I analyzed historical prices and forecast 2006 price trends across a number of dimensions before determining the Destination Market Prices. For example, I reviewed average hourly trends across the day for the three seasons, the distribution of prices within the day and across demand levels, and price trends between peak and off-peak periods. The analysis is detailed in my working papers.

**Why did you decide to forecast 2006 price trends for the Destination Market Price?**

Use of historical prices on an unadjusted basis would result in an inconsistent methodology given that I am analyzing 2006 conditions (and using 2006 projected dispatch costs for generation) in the Delivered Price Test. Moreover, given the recent upward trend in fuel prices, use of historical electricity prices may have otherwise biased the results of the Delivered Price Test. The implied heat rate calculation utilized in my projections is a standard metric used by suppliers and traders in the industry to gauge market conditions, analyze, and forecast future prices. For markets where prices are typically set by gas-fired resources, such as

PJM, the implied heat rate calculation has substantial rigor, especially for short-term forecasts during which time substantial shifts in underlying supply conditions are not expected.

**What were the resulting Destination Market Prices?**

Exhibit 8 contains a table of my projected Destination Market Prices. I defined the Extreme Peak period as the top 10 hours of the season's peak hours. Given the price profile in PJM, I selected an "Extreme Peak" segment only for the summer season. I then defined the super peak for each season as the top 10% of all peak hours ("Top 10% of Peak"). The residual peak hours are represented in the "Rest of Peak" category. The "Offpeak" period proxies for off-peak hours. With the exception of the Extreme Peak, my segments were aligned with those used by Dr. Hieronymus. For the Extreme Peak, Dr. Hieronymus simply uses the top hour. Other practitioners have used the top 50 hours, the top 100 hours, and the top 1% of hours. I typically use the top 10 hours (which can be viewed as covering the highest hour per week during the majority of the summer months or a series of hours associated with a summer's hot spell) because it allows me to capture real price events, rather than low probability price spikes. However, I further augment my selection of the Extreme Peak through the sensitivity analysis.

**Why did you decide to use two different Destination Market Prices?**

Based on my price analysis, I saw a significant differential between prices in PJM East and the wider PJM market. This is not surprising given the binding transmission constraints in this area, which results in very different resources setting market-clearing prices in different areas of PJM. When constraints isolate the PJM East system from the rest of the market, more expensive local resources, such as gas- and oil-fired plants, are used to meet demand and thus set the price inside the transmission constrained area, while the remainder of the market continues to settle on the basis of coal and baseload gas dispatch costs. This dynamic is clearly evident in prices. For example, for calendar year 2004, the load-weighted average annual price in the PJM day-ahead market[14] as a whole was $41.9 per MWh, while Eastern PJM's hub price averaged $45.1 per MWh.

Given the importance of the Destination Market Prices for the FERC's Delivered Price Test, I determined that it was necessary to differentiate between PJM East and the broader market definition. Historical prices that overlap with the Expanded PJM market definition are not directly available from PJM, as Dominion has not joined the market. However, there is strong similarity in underlying fuel mix if we look at PJM Pre-2004 (with Allegheny and coal-rich PJM West hub included) and the current footprint (Expanded PJM less Dominion). Therefore, in contrast to my conclusions with respect to PJM East, I determined that it was not necessary to differentiate between PJM Pre-2004 and Expanded PJM, but critical to separate PJM East from these two other geographical market definitions.

**How do your Destination Market Prices compare with Dr. Hieronymus?**

My Destination Market Prices are on average 47% to 57% higher than those used by Dr. Hieronymus (with the exception of prices during the Extreme Peak), as illustrated in Exhibit 9. I believe the primary driver behind this difference is the adjustment for current market expectations on gas prices. Natural gas prices have moved up over the last few years, and have been especially strong in its upward trajectory the last six months. The NYMEX futures market

[14] Inclusive (on a rolling basis) of all the additional members and zones added throughout 2004.


London Economics International LLC
717 Atlantic Ave, Unit 1A
Boston, MA 02111
www.londoneconomics.com

continues to project commodity prices at Henry Hub in the range of $7/MMbtu to $8/MMBtu for 2006. Given such trends, Dr. Hieronymus' selected Destination Market Prices are generally out of synch with current market conditions.

In addition, I have used location-specific Destination Market Prices, while Dr. Hieronymus has simply applied the same Destination Market Prices across all three geographical markets analyzed.

**What assumptions did you make with respect to new entry and retirement of generation in the Delivered Price Test?**

Though the PJM market is a deregulated market for generation, whereby new generation investment and plant closure decisions are driven by private investment and market economics, PJM's Planning Department is nevertheless involved in approving interconnection agreements, as well as retirement requests. In consideration of the 2006 target date for my analysis, I have included generation under construction or permitted as new entry and announced (and generally approved) retirements through 2006 in the Delivered Price Test analysis. My assumptions are based on the latest market intelligence and consistently reflect on the data maintained by PJM.

New generation projects are required to submit an interconnection request to PJM in order to initiate a generation interconnection feasibility study analysis and system impact study analysis. In addition, they must submit and acquire major permit applications (including critical land use, air, water, emission and operating permits) with their local and regional environmental authorities. Given the very public nature of the project development process for generation, substantial data is available currently on new generation projects and their status. In fact, PJM keeps an updated log of likely new investment based on its queue process and Regional Transmission Expansion Plan ("RTEP"). As of March 2, 2005, PJM had less than 4,000 MW of new capacity slated for commercial operations in 2006/2007, based on project status and commercial online date reported by developer.[15] Dr. Hieronymus cites in his testimony that approximately 5,000 MW of new capacity is expected by 2006/2007.[16] The decline in expected new entry is consistent with the ongoing trend we have seen over the last few years in project development cancellations and delay, as most gas-fired projects are not well placed to compete in a high-priced gas environment. On the basis of recent project delays, I have adjusted downward the new entry assumptions in Dr. Hieronymus' generation database (which I used as the starting point for my analysis) by approximately 1,000 MW.

PJM also analyzes the impact of mothball and unit closure requests. The Planning Department will review a request for retirement typically within 30 days of filing. They will identify any reliability problems, explore solutions, and then issue recommendations for resolution of reliability concerns within a 90 day timeframe. Given this official process, PJM also keeps current records on expected retirements. As of March 24, 2005, PJM expects the retirement of 5,219 MW over the next nine months, based on those plants that have been approved for retirement or where a pending application has found no reliability issues and the unit has requested a retirement date of 2006 or earlier.[17] We have included these retirements in

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[15] Please see www.pjm.com/planning/res-adequacy/downloads/20050302-mw-new-capacity.pdf

[16] Application, Exhibit J-1 at, 74 and Exhibit J-4 at 3.

[17] See http://www.pjm.com/planning/project-queues/gen-retire.html

our analysis. The 5,219 MW is 103 MW more than the total MW of retirements included by Dr. Hieronymus in his analysis.[18]

**What is the combined effect of your assumptions regarding the new entry and retirement of generation compared to Dr. Hieronymus' assumptions?**

By reducing new entry by 1,000 MW and increasing retirements by approximately 103 MW above the aggregate amount used by Dr. Hieronymus in his analysis, the pool of competing supply shrinks and thus the Applicant's market power abilities are amplified. Though the magnitude of the change is not substantial vis-à-vis the overall market size, I believe my figures represent the latest available information on supply considerations given the timing of this testimony versus the date on which Dr. Hieronymus filed his testimony. Thus, my figures better reflect the current outlook for 2006.

**What assumptions did you make with respect to outages in the Delivered Price Test?**

I utilized the most recent Generating Availability Data System ("GADS") database from NERC for historical outages, namely the *REVISED 1999-2003 Generating Availability Report*.[19] I then assigned a class average forced outage rate from the GADS database to each generating unit in the calculation database. For those generation types which are not covered by GADS, such as wind and certain other renewable resources, I surveyed equipment manufacturers and

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[18] In his testimony, Hieronymus states that "PJM forecasts retirements of approximately 3,000 MW and additions of approximately 5,000 MW by 2006/2007." Application, Exhibit J-1 at 74.

[19] http://www.nerc.com/~filez/gar.html

developed a forced outage estimate based on manufacturer's recommended operating cycles and warranties.

**How do the above assumptions with respect to outages compare to those used by Dr. Hieronymus?**

Based on his working papers and generation database, it is clear that Dr. Hieronymus is also using GADS data; however, he notes in one of his working papers that he is using the year 2000 Generating Report. I have used the 2003 report, which reflects the latest information available from NERC on class average forced outages.

**What assumptions did you make in forecasting projected dispatch costs for generation?**

The dispatch costs of generation are an integral part of the Delivered Price Test, as they determine the 'economic' element of deliverability vis-à-vis the Destination Market Price. All generators that have a dispatch price less than or equal to 105% of the Destination Market Price are assumed to be part of the competing supply pool from which the HHIs are estimated for a particular market segment. The *Merger Policy Statement* calls for a forward-looking analysis of market concentration. I therefore believe it is necessary to utilize projections for dispatch costs that reflect future market conditions in the short- to medium-term.

Furthermore, it is important to use the latest market-based forecasts of fuel prices, as fundamentals quickly change in the fuel markets, which in turn has important implications for the relative position of generators within the supply mix and thus the competitive relationship of suppliers in different segments of the market under the Delivered Price Test. Fortunately, many of the fossil fuels have very liquid spot and futures/forward markets and thus an abundance of market data is available.

I have included the following elements in determining dispatch price: projected fuel costs, variable O&M costs, and, where applicable, environmental compliance costs, such as $SO_2$ and $NO_X$ allowance purchase costs. I have used, where available, market-based data to establish the dispatch price for 2006. For example, I have relied on NYMEX futures for determining the commodity component of future fuel prices for coal, oil, and natural gas, as well as market price index data for $SO_2$ and $NO_X$ allowance prices for 2006. Given data availability and reliability, use of market prices would be a preferred approach over propriety or other third-party projection models and escalation figures: third-party projections are done on an infrequent basis (perhaps annually or quarterly) while the market basically reassesses and recalculates its expectation of future prices on a continuous basis.

I have also estimated a number of location-specific fuel price forecasts. The PJM market encompasses a market-area that spans over 2,000 miles and is diverse in its fuel resource mix, and fuel delivery modes. The locational differential in fuel prices is composed of observed historical price differences between various hubs, as I detail in my working papers. Exhibit 7 summarizes the projected fuel prices that I have used on a seasonal basis for the four market-based fuels: gas, coal, distillate fuel oil (fuel oil #2) and residual fuel oil (fuel oil #6).

Similar to the fuel price assumptions, we have used the latest market data on allowance prices for the 2006 $NO_X$ season and 2006 $SO_2$ allowance vintages. Cantor Fitzgerald's *Market Price Index* puts those prices at $760/ton and $3,540/ton for $SO_2$ and $NO_X$, respectively. Variable O&M costs were based on reported average industry estimates by unit type and primary fuel and operating data from various sources, such as FERC Form 1 and EIA Form 411. Each unit was assigned a dollar per MWh adder. The specific assumptions are summarized in my working papers.

***How do your dispatch price assumptions compare to the assumptions used in the Applicants' analysis?***

As I have 'marked-to-market' my fuel and allowance prices to the latest market expectations, my analysis represents the appreciation in fuel prices and allowance prices that has occurred over the recent time horizon and is expected to remain with us through the next one- to three-year timeframe. In contrast, Dr. Hieronymus used historical fuel prices, undifferentiated by geographic area, and scaled those using third-party forecasts[20], rather than market-based data. The result is that he is underestimating the short-term price of key fossil fuels, like gas and oil, and thus possibly biasing his analysis. His use of a single fuel price outlook for all three geographic markets further divorces his analysis from commercial realities.

I believe that my fuel price assumptions are well aligned with the other assumptions in my Delivered Price Test and the overall spirit of the Competitive Analysis Screen, given its forward-looking nature. Exhibit 10 compares the summer period supply curves under my assumptions to those implied in Dr. Hieronymus' analysis.

[20] In Application, Exhibit J-4 at 6, Dr. Hieronymus states that he "escalated to 2006 at rates presented in recent forecasts by EIA."

**What assumptions did you make on the import transmission capacity?**

I concur with Dr. Hieronymus regarding assumptions on the Simultaneous Import Limit ("SIL") for each of the three markets analyzed: PJM East, PJM Pre-2004 and Expanded PJM. Like Dr. Hieronymus, I have assumed a SIL of 7,300 MW into PJM East, based on a study conducted by PSEG's transmission engineering group referenced in Dr. Hieronymus' testimony, and a SIL of 4,300 MW for imports into PJM Pre-2004, based on the maximum level of imports for the capacity market in 2003 as stated in the PJM's *2003 State of the Market*[21] report. For the Expanded PJM market, like Dr. Hieronymus, I use a SIL of 7,500 MW, which is based on PJM's *Simultaneous PJM Import Capability*[22] study.

However, my analysis surrounding the SIL for Expanded PJM differs from the approach taken by Dr. Hieronymus. He notes in his working papers that he has included only MISO and NYISO as relevant first-tier markets. In contrast, I include all relevant first-tier areas surrounding Expanded PJM, including control areas south of PJM such as Duke Power ("Duke"), Carolina Power & Light Company ("CPL") and Tennessee Valley Authority ("TVA"). These markets are relevant to our analysis and should be included as first-tier markets as they are directly interconnected with Expanded PJM, and generators located in these control areas can serve the load in the Expanded PJM market. Moreover, the 7,500 MW SIL estimate developed by the PJM includes resources from all these markets, as I noted briefly above.

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[21] *2003 State of the Market*, PJM Market Monitoring Unit, March 2004

[22] Simultaneous PJM Import Capability, System Operations Division – Transmission, September 2004

I also used a pro rata method that is similar to Dr. Hieronymus' "squeeze down" method for rationing import capacity. The pro rata allocation of each economic slice of external generators is completed on the basis of the relevant market shares and subject to the assumed import limits. For instance, when analyzing the PJM East market, I first established the pool of economic external resources to Expanded PJM. Next, based on their relative market shares, I allocated the SIL of 7,500 MW to these external suppliers and then incorporated them into the supply mix in Expanded PJM. Then, I re-determined the economic pool of resources in Expanded PJM and allocated them to the SIL of 4,600 MW into PJM Pre-2004 based on their relative market shares and incorporated them into the PJM pre-2004 market. I then re-determined once again the economic suppliers within PJM Pre-2004 (with the external resources from Expanded PJM) and allocated the pool of suppliers to the SIL of 7,300 MW into PJM East based on their relative market shares. This group of allocated resources was then brought into the PJM East market and used in conjunction with local PJM East capacity to define the market.

**How did you test the Applicants' proposed mitigation measures?**

Since we do not know exactly which units are going to be divested, I tested the proposed mitigation measures by developing a simple allocation mechanism of the mitigation-eligible units listed in Dr. Hieronymus' Exhibit J-21 and the availability-adjustment method described in Exhibit J-13 in Dr. Hieronymus' testimony. Exhibit J-13 highlights the mitigation scenarios proposed by Dr. Hieronymus for both PJM East and the rest of PJM (PJM Pre-2004 and Expanded PJM). For each market, the exhibit lists the total amount of nuclear (baseload), coal and mid-merit (mid-merit) and peaking mitigation proposed. The mechanism I used to test the proposed mitigation measures simply allocates aggregate classes of capacity for mitigation to each of the relevant economic periods, based on an *a priori* review of the dispatch prices for that group of generation. For instance, nuclear capacity, being baseload, would be allocated to all time periods, while coal and mid-merit units would be allocated as qualified mitigation units across all peak periods (rest of peak, top 10% of peak, and extreme peak). All the demonstrated capacities listed in Exhibit J-13 are derated to account for outages before they are deducted from the Applicants' portfolio pool and 're-assigned' to another supplier I have taken a similar approach in my Delivered Price Test analysis.

**What are the results of the Delivered Price Test you conducted?**

My independent analysis concurs with the overall results of Dr. Hieronymus' analysis of the impact of the merger. The Delivered Price Test results conducted by Dr. Hieronymus suggest that the merger would lead to a more concentrated energy market across a variety of load conditions and in all three seasons tested. As noted in Exhibit 4, Dr. Hieronymus' analysis of Economic Capacity post-merger concludes that there would be HHI screen failures with regards to all energy market segment combinations and seasons and across all three geographical market dimensions prior to mitigation.

Exhibit 11 summarizes the results of my independent Delivered Price Test for Economic Capacity. The tables include the pre-merger and post-merger HHIs and change in HHIs. Exhibit 12 illustrates the results graphically. In all but one instance (shoulder season, top 10% of peak), there are screen failures per the thresholds identified in the *Merger Policy Statement*. Most post-merger HHIs are well above 1,000, with HHI changes averaging over 480 in the thirty market segments analyzed. In addition, in 14 of the 30 geographic and product segments analyzed for Economic Capacity, my analysis produces post-merger HHIs that are higher than those presented by Dr. Hieronymus, as highlighted in Exhibit 13.

**Did you analyze the mitigation of the screen failures for Economic Capacity?**

Yes, I first analyzed the impact of the Applicants' proposed mitigation plan. Then, I examined the Economic Capacity segments (such as 'offpeak' versus 'rest of peak') and seasons that require further mitigation. I then computed the minimum quantity of additional divestitures that would cure the screen failures in my independent analysis. I took into account in my analysis the auction restrictions proposed by the Applicants on buyers of divested assets and blocks of energy under the virtual divestitures, including the market share qualification and maximum purchase quantity.

**What are your conclusions on necessary mitigation?**

My results for the Delivered Price Test of Economic Capacity suggest that the proposed mitigation by the Applicants of 5,500 MW of capacity is insufficient to cure all screen failures. Exhibit 14summarizes the HHIs for Economic Capacity for all three geographic markets after applying the proposed mitigation plan offered by the Applicants. In six of the 30 product segments studied across the three geographical market dimensions (i.e., summer 'rest of peak' and shoulder 'rest of peak' periods for each of the three geographic markets), my analysis results in screen failures per the FERC's *Merger Policy Statement.* The screen failures occur in the summer and shoulder 'Rest of Peak' periods for Economic Capacity. Notably, screen failures continue across all three geographical markets. Based on the results of the Delivered Price Test, an additional 890 MW of divestitures in Expanded PJM is necessary to cure the screen failures.

**Did you analyze any sensitivities around these results?**

Yes, I have also looked at the results of the Delivered Price Test assuming different market price trends. My baseline analysis captures three load segments in each season (four segments in the summer) and therefore does not provide a detailed distribution of possible prices and load. Testing different sensitivities in my analysis enables me to better understand the discontinuities in the supply curve and how those relate to load and whether they provide the Applicant with otherwise unanticipated opportunities to unleash its market power.

The sensitivity analysis is vital to testing the conclusions reached in the baseline analysis, as it expands the range of load segments and adds an additional layer of robustness. The *Merger Policy Statement* advocates sensitivity analysis in such a context. Surprisingly, Dr. Hieronymus did not conduct any sensitivity analysis for his Delivered Price Test.

I chose to test a 25% higher case and a 25% lower case around my baseline Destination Market Prices. The sensitivities suggest that when the price thresholds are increased by 25%, 10 of the 30 post merger HHI levels increase (the change in HHI also expands). Similarly, when we look at the sensitivity analysis in which the price thresholds have been decreased by 25%, 11 of the 30 HHI levels increase, along with a commensurate increase in the change in HHI. Also, for both sensitivities, the screen failures continue across all three geographical market dimensions. In three instances under the scenario in which the price thresholds are increased by 25%, my analysis suggests that an additional 960 MW of divestitures is necessary to cure the screen failure for PJM East and an additional 50 MW when analyzing the PJM Pre-2004 geographic dimension, as shown in Exhibit 16 and Exhibit 17.

**Did you conduct any other horizontal market power analyses for the energy markets?**

Yes, I also looked at two other alternative measures of market power: the market share screen and the Concentration Test for Spare Capacity.

**4.2.1 Other metrics of market power potential – the market share screen**

**What is the foundation for analyzing the market share of a firm for market power evaluation?**

Market shares are yet another parameter that can be used to evaluate the size of the firm vis-à-vis the rest of the market. The Delivered Price Test's screen failures are defined in terms of HHI levels and changes in the HHI levels. However, the *Merger Policy Statement* requires that the Applicants also provide market shares, as they are the core of the HHI calculation. According to Dr. Hieronymus' calculations, market shares for Economic Capacity are as high as 47% post-merger and remain well over 20% in most of the market segments tested, even after the Applicants' proposed mitigation is accounted for. In my independent Competitive Screen Analysis, post merger market shares for the Applicant range from 22% to 47%, as summarized in Exhibit 18. In 20 of the 30 product segments analyzed, my market share estimates for the Applicants' post-merger case are higher than those presented by Dr. Hieronymus. Even after applying Applicants' proposed mitigation measures, market shares from my Economic Capacity HHI range from 5% to over 29%, with 23 out of 30 segments producing market shares above 20%.

In addition to the market shares that are reported as part of the Delivered Price Test, the FERC has recently espoused a market share screen for evaluation of generation market power in the context of market-based rate ("MBR") authorizations. The MBR market share screen looks at seasonal market share calculations using uncommitted capacity, which is nameplate capacity adjusted for a measure of native load obligations and other commitments. The FERC has allowed uncommitted capacity to be adjusted for operating reserve requirements and planned outages.[23] An applicant must show that it has less than 20% market share across all seasons in order to pass this screen under Section 205 of the FPA. *Failure of this MBR market share screen* carries with it a presumption of market power which the applicant needs to disprove or otherwise face mitigation.

**What other analysis did you complete using market share measures?**

I completed a calculation of the seasonal market shares for the Applicants on a post merger basis, with and without their proposed mitigation measures, and according to the methodologies defined in the April 14th Order. The results suggest that the Applicants would have seasonal market shares ranging from 29.8% to 31.4% post-merger and would thus fail the MBR market share screen. Even after the reduction in capacity per the Applicants' proposed mitigation plan, the Applicants fail the screen.

**What are the key assumptions used in this analysis?**

In performing this analysis, I relied on the FERC's revised methodology for use in the evaluation of generation market power in the context of market-based rate authorization as described in the April 14th Order. The MBR market share screen evaluates an applicant's share

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[23] *Based on reported outages on FERC Form 714 for that season.*

of the capacity market on a seasonal basis. The applicant's capacity is adjusted for long-term commitments, outages, operating reserves, and potential hydro deratings. A supplier with less than a 20% market share in the relevant market for all four seasons passes the MBR market share screen.

*For the purposes of my analysis and in the context of this filing, I found it appropriate to* use some of Dr. Hieronymus' assumptions in Exelon's recent Triennial Review (which is currently awaiting FERC review)[24], notably their installed capacity and load figures for Expanded PJM. My analysis of the merged entity ("EEG") therefore reflects Dr. Hieronymus' assumptions for Exelon in addition to my own assumptions, principally relating to PSEG. I briefly review below the other key assumptions and data sources used for the MBR market share screen calculation.

**Geographical Market:** The geographical market used in the market share screen is defined as "Expanded PJM" which includes, in addition to "PJM Classic" ("MAAC"), Allegheny, the east zone of American Electric Power ("AEP"), Dayton Power & Light ("DPL"), Duquesne Light ("Duquesne"), and Dominion Virginia Power ("DVP").

**Simultaneous import capability:** With regards to the Simultaneous Import Limit (SIL), I have applied PJM's estimate of 7,500 MW, which I have also used in the Delivered Price Test. I applied any remaining import capacity, not used by the Applicants given their first tier holdings, to uncommitted competing supply in Market Share Screen, pursuant to FERC's guidelines in Paragraph 95 of the April 14th Order.

[24] Exelon Generation Company, LLC, Triennial Review, FERC ¶ ER-98-1734-007 (2004).

**Operating reserves:** I relied on data provided by PJM[25] on operating reserve targets. I used the sum of "primary" and "secondary" reserves, and allocated them between the Applicant and competitive suppliers based on the generation capacity owned or controlled. The total operating reserves for Expanded PJM sum to 4,618 MW.

**Planned outages:** FERC noted in the April 14th Order that "planned outages (that were done in accordance with good utility practice) for each season will be considered"[26] as an adjustment to total installed capacity. In my analysis, I used Dr. Hieronymus' assumptions in which he relied on planned outages information which is consistent with the FERC Form 714 data provided by PJM to Exelon, and adjusted for planned outages for Exelon's units in PJM. He then used company-specific data for planned outages for Exelon's units in the historic 'classic PJM' area and then used FERC Form 714 data for ComEd, AEP, DPL, Duquesne and DVP. In following with this method, I allocated the planned outages to the merged entity on the basis on ownership or control of generation capacity.

**Derating of hydroelectric capacity:** FERC's interim methodology also allows for the derating of hydroelectric capacity to more accurately represent the actual operational capacity of these assets. However, to be conservative, I have not derated hydroelectric capacity in my analysis. As most of the hydro capacity in PJM Expanded is owned by competing suppliers, this assumption favors the Applicants.

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[25] PJM Emergency Procedures, PJM presentation dated August 5, 2004, pg. 17.

[26] April 14th Order at Paragraph 100.

**Applicant's Uncommitted Supply:** The Applicant's uncommitted capacity located in Expanded PJM is 40,304 MW. The Applicant's affiliated uncommitted capacity in surrounding first-tier regions is 1,787 MW (1,026 MW from MISO and 761 MW from NYISO), resulting in a total affiliated uncommitted supply of 42,091 MW before external import constraints are assessed and prior to any adjustments for hydro derating, operating reserves, and outages.

**Native Load Obligations:** I adjusted EEG's generating capacity to account for native load obligations. I only included native load obligations that would hold for 24 months as my analysis is forward looking. As a result, I have not allocated any native load obligations to PSEG, whose native load obligations stem from its New Jersey Basic Generation Service Auction ("BGS auction") for which it has commitments ending in 2006. A renewed auction is set to take place then, and with the outcome being uncertain, I did not want to speculate on what amount of load PSEG would continue to serve beyond 2006. With regards to Exelon, I have included PECO's peak load obligations and ComEd's obligation as a provider of last resort ("POLR") which account for approximately 14,000 MW on a combined basis.

**What are the calculations underlying the market share screen?**

The calculation of the market share screen is straightforward. An applicant's unaffiliated uncommitted supply is adjusted for operating reserves, planned outages and native load obligations in order to obtain its uncommitted capacity. Accordingly, the remaining capacity in the market is adjusted in the same manner. The market share is obtained by simply dividing the applicant's uncommitted capacity by the total uncommitted supply of the market.

I performed the market share analysis under two scenarios, a merger between Exelon and PSEG with the proposed 5,500 MW of mitigation and a merger between Exelon and PSEG without any mitigation. Under both scenarios, the Applicants would fail the Market Share Screen in each of the seasons. Even after mitigation, the EEG's market share is above 23% for all seasons. Exhibit 19 summarizes the results of the market share analysis.

**What are your conclusions with respect to the market share analysis?**

In order to correct the 20% seasonal market share screen failure, the Applicants would need to divest an additional 3,000 MW of capacity, above and beyond their proposed level of 5,500 MW. I recognize that the interim market power screens used by FERC under Section 205 of the FPA differ from those that the FERC has considered in Section 203 proceedings. Nevertheless, the FERC, itself notes the interplay between the Competitive Analysis Screen and market-based rates in the *Merger Policy Statement*: "our concern with short-lived periods of high concentration is greater if the merged firm will have market-based pricing authority. Without such authority, the firm may not be able to substantially raise prices."[27] Hence, it would illogical for the FERC to approve the merger and proposed mitigation plan under Section 203 only to have to address the same issues under Section 205 of the FPA after the Applicants make their market-based rate authorization filing.

### 4.2.2 Concentration Test of Spare Capacity

**What is the Concentration Test for Spare Capacity?**

This test evaluates the concentration of spare capacity on peak competing for the next increment of demand.

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[27] FERC. 18 CFR PART 2 (Docket No. RM96-6-000). "Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement" ORDER NO. 592. (Issued December 18, 1996), pg. 78.

**Please describe the theoretical basis for the Concentration Test of Spare Capacity.**

Though the Delivered Price Test has served the FERC well in the past, there are several well-know theoretical simplifications presumed by the HHI measure in the Delivered Price Test vis-à-vis actual markets. HHIs – whether in the Delivered Price Test or in another analysis - do *not address the demand-side characteristics of the market.* Demand elasticity, in fact, can be a very strong inhibitor to market power abuses, but that is not recognized by the HHI or any other concentration measures that focus solely on supply. At the same time, in markets with inelastic demand, HHI measures may underestimate the extent of market power, especially at peak demand periods when supply resources are exhausted. This is an important consideration to keep in mind given the pricing rules in PJM and other nodal markets.

PJM operates under a single market-clearing price principle. This means that, once a price is set for energy, all generators operating in the market receive the same price (leaving aside marginal losses and transmission congestion). Furthermore, in nodal markets like PJM, the market-clearing price is set in reference to the next available bid or the cost of serving the next increment of load, so that the opportunity costs of electricity are appropriately reflected. So for purposes of price, the most important generators are those that are price setting or "marginal." All generators that are dispatched at full capacity are effectively infra-marginal. The FERC's Delivered Price Test, by design, looks at the concentration of the infra-marginal generation and typically ignores competition by suppliers to fulfill the next increment of demand outside of the 5% band above the Destination Market Price.

This can lead to some paradoxical outcomes. Let us assume we are looking at the highest demand hour of a market, so we are effectively at the top of the supply curve. The Delivered Price Test will be measuring concentration of all generators effectively 'already running' at the selected price threshold, and since we estimate the Delivered Price Test on the basis of full capacity, most of these generators will not have spare capacity to increase output to frustrate market power abuses. Given that we are looking at all resources on the supply curve, or almost all resources, we will have a fairly low concentration measure. However, the market concentration of 'available generation' to meet the next increment of demand should be very high, possibly even approaching 10,000 if competing resources have been fully exhausted.

**Please describe the methodology used in this test.**

This test considers the level of concentration of suppliers before and after a merger (and thus the impact of the merger on the level of competition) who are competing to meet the next increment of demand. The test is run as an HHI analysis focusing on 'spare' capacity (i.e., not dispatched, but available) above 105% of the Destination Market Price. I believe that this test can provide valuable insight into the Applicants' ability possibly to exercise market power at the top of the supply curve. Since the objective of this test is to highlight the availability of competition to frustrate strategic behavior on peak, I will only focus on the results for the peak periods of the market.

**What are your assumptions for the Concentration Test of Spare Capacity?**

The test is performed using the same data as the Delivered Price Test, and thus I use the same set of assumptions on geographic and product dimensions, Destination Market Prices, the new entry and retirement of generation, outages rates and dispatch costs. One important difference with the Delivered Price Test is the allocation of import transmission capacity. Since we are evaluating the 'spare' capacity at very high price levels, I have assumed that the import capacity has been effectively maximized and dispatched, and therefore it should not be considered in the current analysis. This assumption is especially apt for the PJM market, since *power typically flows into PJM from the west and south and is either consumed or flows north* and eastward to export destinations.

**What are the results of your analysis?**

I present the results of the Concentration Test for Spare Capacity in Exhibit 20. Logically, the results indicate that the HHIs tend to increase as we move further up the supply curve (and price levels rise). The Applicants fail the Concentration Test for Spare Capacity for all periods in PJM East. Moreover, the post merger HHIs for PJM East during summer peaks are as high as 4,000 with the changes in HHI exceeding 1,700. The Applicants' proposed divestiture of 1,900 MW of mid-merit and peaking capacity cure many of the screen failures, but the Extreme Peak requires the divestiture of additional peaking capacity. This analysis clearly indicates that the Applicants would jointly own substantial capacity (around 60%) at the top of the supply curve. They could use this capacity, if conditions warrant, raising prices, perhaps substantially, and extracting market power rents.

### 4.3 Horizontal market power analysis of capacity markets

**Did you do a Competitive Analysis Screen for other markets?**

Yes, I also did an HHI analysis of the PJM Capacity Credit market.

**Please describe the PJM capacity market.**

In the Capacity Credit market (also referred to as "Installed Capacity Market" or "ICAP" market), generation owners sell Capacity Credits associated with their facilities. By selling these Capacity Credits, they are then obligated to offer this capacity into the PJM energy market. In other words, generators are essentially paid an availability payment for having capacity available for offer into the day-ahead PJM energy market. Load serving entities must purchase sufficient Capacity Credits to meet the regulatory-specified reserve margin above their projected load. It is important to note that resources that are made available to supply capacity into the Capacity Credit market are de-rated to reflect forced outages; thus, they are remunerated on the basis of their unforced capacity or "UCAP."

Since 2003, the PJM Capacity Credit market has encompassed the Mid-Atlantic and Allegheny Energy Company control areas (equivalent to PJM Pre-2004 in our Competitive Screen Analysis) and was operated on the basis of Unforced Capacity auctions conducted on a daily, monthly, and multi-monthly basis. PJM introduced its Daily Capacity Markets on January 1, 1999, with Monthly and Multi-monthly Capacity Markets following in mid-1999. Integration of the Commonwealth Edison Company control area in 2004 led to development of a separate Northern Illinois Control Area ("NICA") Capacity Credit market which also operates through daily, monthly, and multi-monthly auctions. As of June 1, 2005[28], however, PJM will operate a single uniform capacity credit market which encompasses all PJM members and which pays the same price to all generators regardless of the PJM footprint location or operating characteristics.

[28] PJM is planning to have NICA join the PJM Unforced Capacity Credit market at the expiration of its "Interim Period" on May 31, 2005.

PJM is in the process of evaluating viable enhancements to the prevailing PJM Capacity Market, including a Reliability Pricing Model ("RPM") that would be based on a four year locational forward capacity auction that would yield locational ICAP prices. This proposed framework would effectively change current the market-wide Capacity Credit market into a number of regional or even sub-regional markets. Although PJM intended to file the RPM with the FERC by mid-2005 to ensure that the system is operational by 2006, the Members Committee rejected the proposed draft resulting in a standstill until at least the May 5, 2005 PJM Board Meeting.

***What market definition did you apply in your concentration analysis?***

As of June 1, 2005, there will be a single PJM Capacity Credit market, which would suggest that the Expanded PJM market is the relevant focal point of the analysis. Thus, I estimated the HHIs for the Expanded PJM market. However, in order to be able to ascertain the possible impact of the merger if a locational capacity market develops, I also tested the market concentration and changes in market concentration due to the merger in Eastern PJM.

**What are some of the key considerations made in your analysis of the capacity market?**

I adjusted the installed capacity attributable to each supplier so as to more accurately reflect the nature of the underlying product traded. Under current market rules, generators cannot sell, nor be remunerated for, the entire installed capacity of their generation. The market transacts on the basis of unforced capacity, which is installed capacity derated for rolling average historical forced outages rates. Unit-specific historical forced outages rates are confidential and thus not available; however, the FERC's guidelines under the *Merger Policy Statement* allow us to make reasonable assumptions.

I estimated an unforced capacity measure for each unit using the latest available information for industry-wide class average forced outage rates collected by NERC in its GADS database (the same data that I used in the Delivered Price Test for Economic Capacity). Thus, each unit was assigned a forced outage rate assumption, based on its technology, fuel type and overall size. This reasonable assumption allowed me to make a more precise estimate of market concentration. I also incorporated the assumptions for new entry and retirement of generation that I developed for the Delivered Price Test for Economic Capacity.

**Why do you think it was necessary to make this adjustment?**

As can be seen in Exhibit 3, the Applicants will own 100% of the nuclear fleet in PJM East and over 65% of the nuclear fleet in Expanded PJM. The forced outage rates for the nuclear fleet are substantially lower than for other resources, which will increase the overall UCAP of the Applicants' portfolio as compared to the rest of the market. In my opinion, an ICAP measure would not represent this relationship accurately.

**Did you incorporate import transmission capacity into your Capacity Credit market analysis?**

Current market rules permit external resources to participate in PJM's capacity markets so long as they offer on a unit-specific transaction basis, which requires that a physical unit is identified. External resources must also have proof of firm transmission rights into PJM, and agree to abide by the other ICAP market requirements, such as the must offer requirement into the day-ahead energy market.

Therefore, I have included external resources as qualified suppliers (up to the limit of the import transmission capacity) into the PJM Capacity Credit market. I have used the same figures and assumptions as was used in the Delivered Price Test for Economic Capacity - *namely 7,500 MW SIL into Expanded PJM and 7,300 MW SIL into PJM East. I modeled two* scenarios in order to test different assumptions in regards to the allocation of this import capacity to suppliers. The first scenario assumed that the import capacity would be attributed to four of the largest PJM suppliers, excluding the Applicants for the sake of conservativeness. The second scenario allocated the import capacity in equal MW blocks to each market participant. This method is a reasonable approximation of the unit commitment procedural constraint on external resources, as the average unit size in Expanded PJM's first tier markets (67 MW) is smaller than the MW block (163 MW for Expanded PJM[29] and 159 MW for PJM East[30]) assigned to each firm in our scenario. I believe both cases are generally more reasonable - and more objective to the analysis - than the highly stylized assumption made by Dr. Hieronymus.

**Please describe and comment on Dr. Hieronymus' ICAP market concentration analysis.**

Dr. Hieronymus finds that the merger will result in serious market power concerns for Eastern PJM, given the high concentration in the market prior to merger. The post-merger HHI in his analysis is equal to 2,196, with an HHI change of over 900. Although the pre-merger Expanded PJM market appears unconcentrated, the merger will result in an HHI of 1,044 with

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[29] Based on 7,300 MW total import capacity, divided by 46 suppliers.

[30] *Based on 7,500 MW total import capacity, divided by 46 suppliers.*

an HHI change of 245 points, implying once again a screen failure. Dr. Hieronymus concludes that the merger will require mitigation of some 5,300 MW of installed capacity to cure market screen failures in his ICAP test.

I have three important concerns with Dr. Hieronymus' analysis and conclusions:

First, Dr. Hieronymus states that the divestiture of "mid-merit and peaking generation significantly mitigates any concerns in the ICAP market"[31] and that remaining screen failures will be mitigated through a zero offer price strategy for the lesser of 2,400 MW or the unforced capacity position of the Applicants less 100 MW.[32] However, a zero offer price may not necessarily mitigate all market power concerns, since that capacity would receive the uniform market-clearing price and thus earn greater profits from the bidding of the remainder of the Applicants' portfolio. At the minimum, as I discuss further below, capacity rights must be included with the baseload virtual divestitures.

Second, Dr. Hieronymus foregoes making adjustments to capacity for forced outages due to lack of data. This exaggerates the capacity of other suppliers relative to the Applicants, as the nuclear-dominated portfolio owned by the Applicants should be expected to achieve a much lower forced outage rate than other competing suppliers and thus a much higher UCAP and share of the Capacity Credit market.

Third, Dr. Hieronymus assumes that the entire import transmission capacity will be allocated to four firms with zero capacity holdings in PJM. This is a subjective assumption that

[31] Application, Exhibit J1 at- 11.

[32] Application at 39.

is difficult to support. There is nothing in the market rules or current commercial arrangements in the industry that would prevent current suppliers in PJM from importing external capacity. In fact, many of the current suppliers within PJM also have capacity in first tier-markets. Thus, they would be well-positioned to arbitrage between different ICAP institutions and market-clearing prices, subject to firm transmission availability. Dr. Hieronymus' assumption in this regard benefits the Applicants, as it suppresses overall HHI levels. My analysis suggests that the size of the minimum mitigation measures is highly dependent on Dr. Hieronymus' assumptions regarding import allocation; thus, it is important to consider alternative assumptions.

**Please describe your selection of import assumptions for the scenarios you completed.**

I considered two possible allocation methods for import capacity and external supply into the PJM Capacity Credit market. I looked at a case where the external supply (vis-à-vis the SIL) was assigned to the top four suppliers within Expanded PJM, excluding the Applicants. The second scenario evaluated the case where external supply was more widely allocated - each supplier (including the Applicants) in the relevant market was allocated an equivalent block of external capacity. The two scenarios impact the conclusions in complementary fashion as they straddle the minimum mitigation requirements. While the first scenario disproportionately increases the mitigation requirements for Expanded PJM, the second scenario has a relatively larger impact (as compared to the first) on PJM East.

**What are the results of your independent analysis of ICAP?**

When (a) adjusting for UCAP derates, (b) implementing a more realistic treatment of imports[33] - by allocating import capacity in equal blocks to all existing suppliers or to the top four existing suppliers [34] -- and (c) incorporating the extra retirements that Dr. Hieronymus failed to account for in his analysis[35], both Expanded PJM and PJM East experience market screen failures which require mitigation of additional capacity above and beyond the figures suggested by Dr. Hieronymus in his testimony and substantially beyond the levels proposed by the Applicants in their mitigation plan.[36]

In the first scenario, we looked at an alternative but probably more likely allocation of import capacity to four players - rather than assuming four external players, we allocated the capacity to four incumbents of the PJM market. We thus allocated the import capacity to the four largest suppliers, excluding Exelon and PSEG. As a result of these assumptions changes,

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[33] As compared to Dr. Hieronymus' scenario in which he allocates imports to entirely new players in the market, thereby effectively diluting the existing players' market shares

[34] Which is assumed to satisfy in approximation the procedural constraint of unit-specific commitment

[35] The extra retirements reflect PJM's updates to the PJM retirements list as of March 24, 2005.

[36] In Expanded PJM, Dr. Hieronymus suggests that the divestiture of 2,300 MW would be sufficient in his analysis to cure screen failures for the PJM Capacity Credit market. The Applicants plan a divestiture of 2,900 MW of assets (as part of the mitigation for the Economic Capacity screen failures); thus, the ICAP mitigations are below the levels of mitigation being required by the Delivered Price Test for Economic Capacity in this instance. For PJM East, Dr. Hieronymus' analysis requires mitigation of some 5,300 MW of capacity in order to mitigate his estimated screen failures for the PJM Capacity Credit market. However, the Applicants are proposing only 2,900 MW of divestitures, as the remaining portion of the 5,500 mitigation quantity is nuclear, which will not have capacity entitlements associated with it according to the Applicants' proposed mitigation plan. The Applicants propose to mitigate the remaining 2,400 MW of ICAP screen failure by offering into the their net UCAP position less 100 MW into the PJM Capacity Credit auctions at a price of zero. I discuss the inadequacies of this mitigation component later in my testimony. For the sake of clarity, I will refer to the total quantity of necessary capacity mitigation proposed by Dr. Hieronymus, and then compare against the quantity of outright divestitures that have actually been planned by the Applicants.

the minimum mitigation amounts for the Applicants rises substantially over Dr. Hieronymus' proposed amounts. In Expanded PJM, 7,550 MW of capacity on an ICAP basis (or 6,643 MW on an UCAP-adjusted basis) is required in order to mitigate screen failures. This is an additional 5,250 MW of capacity-based divestitures over the 2,300 MW that Dr. Hieronymus suggested as sufficient to cure screen failures in his analysis. In the context of the Applicants' overall proposed mitigation plan, where they have already committed to selling 2,900 MW in order to cure the Economic Capacity (energy market) screen failures, the incremental divestiture requirement would be 4,650 MW.

In PJM East, Dr. Hieronymus concludes that the Applicants have to divest 5,300 MW of capacity to cure the capacity screen failures. My independent analysis suggests that these figures are not nearly sufficient to mitigate screen failures in PJM East's capacity market. In my analysis, to cure capacity market screen failures resulting from the merger in PJM East, the Applicants would in fact have to divest 5,385 MW of capacity on an ICAP basis (equivalent to 4,579 MW on a UCAP-adjusted basis). This is an additional 85 MW over the amount proposed by Dr. Hieronymus.[37] Note however, that in the context of the Applicants' proposed mitigation plan, where only 2,900 MW of capacity is actually being proposed to be divested; my capacity screen failures require an additional divestiture of 2,485 MW.

It is also important to note that if I were to allocate import capacity strictly to the four largest suppliers, the minimum mitigation amounts for the Applicants would rise even further.

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[37] This conclusion is taking into account the Applicant's proposed divestiture restrictions (i.e., that a supplier with less than 3% market share can only purchase 50% of the divested capacity and that a supplier with more than 3% market share but less than 5% market share can only purchase 25% of the divested capacity).

Exhibit 21 provides a summary of the PJM Capacity Credit Market HHIs under this scenario and contrasts the results against the analysis completed by Dr. Hieronymus.

Under the second scenario, I allocated import capacity in equal blocks to all suppliers. This is assumed to satisfy in approximation the procedural constraint of unit-specific commitment. To successfully cure screen failures resulting from the proposed merger, Expanded PJM would require a divestiture of 4,201 MW on an installed capacity basis (or 3,451 MW on a UCAP-adjusted basis). This is an additional 1,901 MW of capacity when compared to Dr. Hieronymus' conclusion or, alternatively an additional 1,301 MW given the amount of divestitures proposed by the Applicants to cure the Economic Capacity screen failures. Similarly, mitigation of market screen failures in the PJM East would require a divestiture of 5,621 MW of installed capacity on an ICAP basis (or 4,804 MW on a UCAP-adjusted basis), according to my analysis. This is an additional 321 MW of capacity over the figure suggested by Dr. Hieronymus for PJM East, but an additional 2,721 MW in the context of what the Applicants' have proposed to divest. Exhibit 21 provides a summary of the PJM Capacity Credit market HHIs under this second scenario.

**What are your concluding remarks with regards to the capacity credit market?**

The Applicants' proposed mitigation plan for the Capacity Credit market is inadequate. As of June 1, 2005, there will be a single PJM Capacity Credit Market, which would suggest that the Expanded PJM geographic market is the relevant focal point of the analysis. The HHI estimates shows that the Applicants need to divest somewhere between 1,301 MW to over 4,650 MW of incremental capacity above the 2,900 MW that the Applicants have committed to divesting. If a LICAP market develops, the area of concern is of course the PJM East region.

Depending on the allocation of the SIL, the PJM East market region may require an increase in divestiture amounts in the range of 2,485 MW to 2,721 MW, above the 2,900 MW that the Applicants have committed to physically divesting.

### 4.4 Horizontal market power analysis of ancillary services

**Please describe briefly the ancillary services markets in PJM.**

PJM currently operates two markets for ancillary services: spinning reserves and regulation. Spinning reserves provide a stand-by source of electricity in case of unexpected system imbalances; whereas regulation corrects for short-term changes in electricity use on a real-time basis, in order to protect the stability of the power system. Both services are currently compensated for on the basis of market-based rates. Other ancillary services such as black start capability, reactive control, and voltage support are provided for on a cost-basis.

**How does the spinning reserve market work?**

Spinning reserves are not settled through an independent product market as PJM makes no initial differentiation between capacity offered to supply energy versus reserves. Rather than creating a distinct market for operating reserves, PJM co-optimizes the bids it receives from generators. First, PJM matches energy offers and bids in the day ahead energy market and guarantees a committed generating resource that it will receive its bid value. Units scheduled and dispatched by PJM are checked to determine if each recovered its operating costs, based on its bid, through the payments that it receives in the energy market over the entire operating day. PJM compensates generators for the difference between their cost of providing pool-scheduled reserves and the hourly market-clearing price of energy; thus, the generators' bids for the energy market are also used to determine the incremental operating reserve credit. Currently, the spinning offer price submitted for a unit cannot exceed the maximum value of the unit's operating and maintenance cost plus a $7.50 per MWh margin.

Under the current market rules for regulation, generation owners receive payment for both pool-scheduled and self-scheduled regulation service they provide at the hourly market-clearing regulation price. In addition, incremental credits are also provided to a pool-scheduled generator for any portion of its regulation bid plus opportunity cost that is not recovered by the market-based regulation revenues. Regulation prices are subject to a $100 per MWh offer cap for regulation services offered within PJM East (MAAC). Regulation offered for any zone that is comprised of ECAR and MAIN control zones, however, is currently cost-based (including opportunity costs) plus $7.50 per MWh.

**Do you have any comments on the Applicants' analysis of market power issues in ancillary services?**

According to Dr. Hieronymus, Exelon's regulation-equipped units represent about 13% of the Mid-Atlantic region's total regulation capability and PSEG's regulation units account for another 12% of the total. Based on data from PJM's *State of the Market* report, Dr. Hieronymus concludes that both players are not pivotal suppliers of regulation service and so do not possess the capability to exercise market power. However, that analysis ignores the potential for market concentration to increase if the divested units are acquired by entities that already possess large fleets of regulation-capable units.

According to Dr. Hieronymus' testimony, Exelon's spinning-capable units represent about 6% of the Mid-Atlantic's total spinning reserve capability. The share for PSEG's spinning-capable units stands at some 39%. Relying on an analysis conducted by PJM and its Market Monitoring Unit ("MMU"), Dr. Hieronymus states that, although combination of Exelon and PSEG into a single entity would result in an HHI change of approximately 500 points, the proposed divestiture of fossil generation (for mitigating screen failures under the Delivered Price Test of Economic Capacity) will result in more diluted spinning capability for the Applicants. This conclusion, however, assumes that Applicants will divest assets with spinning reserve capabilities (i.e., sufficient ramp rates). Since Applicants have not identified the plants that will be divested, there is no guarantee that this will occur.

Based on the analysis conducted by the PJM MMU, high levels of market concentration existed in both these markets historically. If ancillary services and energy are truly substitutes (and thus belong to the a single market, rather than separate markets), then the market power analysis completed for energy should – in theory - be sufficient to safeguard ancillary services, as well. Similarly, the required mitigation would also cover the ancillary services market in the case of a single market definition for energy and ancillary services.

*Dr. Hieronymus suggests this in his testimony by noting that "[regulation and spinning* reserves] are intrinsically linked... [and that] prices in the energy market ... primarily determine the cost of producing regulation and Tier 1 spin."[38] However, he does not offer any *quantitative analysis to confirm his hypothesis. At the minimum, I would recommend that the*

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[38] Application, Exhibit J-1 at 65.

FERC request that the Applicants and their technical witness further substantiate these claims. There are a number of well-accepted quantitative techniques that could be used to statistically analyze the *integration levels between energy and ancillary services prices in PJM, which I* think would provide useful evidence on which to evaluate the market definition hypothesis.[39] Lastly, the Applicants' contention that the proposed mitigation plan for energy also satisfies ancillary services market concerns is based partially on speculation at this time and cannot be evaluated until Applicants provide a definitive list of the assets to be divested and their technical capabilities.

[39] For example, price correlation analysis, Granger price causality analysis, and co-integration (if there are unit root characteristics present in the price data) could be used to look at market integration. In addition, econometric studies of cross-price elasticities could be useful in determining whether or not ancillary services and energy are distinct markets, in which case they would require distinct mitigation packages, or part of a single market.

# 5 Adequacy of proposed mitigation measures

**Please describe the mitigation plan proposed by the Applicants.**

The Applicants propose a multi-stage divestiture process that is intended to mitigate all screen failures in the immediate-, interim-, and long-term time frames. Exhibit 23 illustrates the precise duration of each stage and the key elements of the mitigation plan proposed by the Applicants.

In order to mitigate screen failures under the Delivered Price Test for Economic Capacity (energy), the Applicants propose to divest a total of 5,500 MW of capacity: 2,900 MW of intermediate and peaking capacity and an additional 2,600 MW of baseload capacity. 5,300 MW of that amount will be located in PJM East, with the 200 MW of nuclear capacity to be located elsewhere in PJM. With respect to peaking, coal, and mid-merit capacity, the companies proposed to divest some 2,900 MW of capacity (through outright sales). Included in this proposed divestiture is 1,000 MW of peaking capacity and 1,900 MW of mid-merit capacity (which includes at least 550 MW of coal-fired capacity). The Applicants state that the divestiture will occur either through a swap of assets with owners of generation located outside of Expanded PJM or through an outright sale of the generating facility.

Since Dr. Hieronymus' analysis shows that screen failures also occur during off-peak periods, the Applicants propose "virtual divestiture" of an additional 2,600 MW of capacity (referred to as the "Baseload Mitigation Amount") through auctioning off long-term firm energy rights to baseload nuclear energy - rather than outright asset sales. The Applicants propose to conduct the virtual divestiture in two forms: (1) a firm sales contract for a term of at least 15 years, or (2) an annual auction, in 25 MW blocks, of 3-year firm entitlements to baseload energy. Importantly, the nuclear "virtual divestitures" do not include rights to capacity credits from these units.

For the 5,500 MW of divestitures, the Applicants have proposed a potential list of over 17,000 MW of capacity from which they will select the actual units for divestiture and long-term contracting. Exhibit 24 illustrates the supply curve in PJM East and Expanded PJM with the Applicants' mitigation eligible units highlighted. The assets earmarked for divestiture have different operating characteristics and are distributed throughout the supply curve. The Applicants would like to have the ability to select the units to be divested after the Commission approves the merger. However, this raises substantial uncertainties for the FERC and interested parties. Without a definitive list of the assets to be divested, it is very difficult to understand and evaluate all of the nuances of possible mitigation alternatives. There is a high risk that the FERC could approve the merger on the basis of merger safeguards that do not materialize. This also raises the fundamental issue of interchangeability, which I discuss further below.

For interim mitigation, the Applicants propose divestiture through sale of rights of 2,900 MW of energy and capacity from designated coal, mid-merit and peaking facilities in PJM East with contract terms ranging between 1 and 18 months. The divestiture is expected to take place no later than within 30 days following the end of the month in which the merger transaction closes. Until the entire 2,900 MW of capacity is committed under interim mitigation contracts, the Applicants plan to bid 2,900 MW into the PJM day-ahead market (and, if not dispatched, into the PJM real-time) at a price not to exceed the equivalent of PJM cost-capped rates and bid the net portion of their unforced capacity position less 100 MW at a zero price in the PJM

Capacity Credit auctions. For interim mitigation of baseload nuclear capacity, applicants *propose to conduct an auction of interim firm entitlements to firm 25 MW blocks of energy but* with shorter terms than the three-year product in the long-term mitigation plan and with the interim energy contract terms coinciding with the terms of products most commonly purchased in the PJM markets. The interim baseload auctions will be completed within 90 days following the month in which the merger transaction closes. Until that time, Applicants will bid all of their PJM East nuclear generation into the PJM day-ahead market at a price of zero.

In addition to the mitigation measures discussed above, the Applicants have proposed *certain restrictions on potential buyers of the divested capacity: no more than half of the 5,500* MW divestiture amount (i.e. 2,750 MW) will be sold to a single purchaser. A qualified buyer will need to have a market share of less than 5%. The Applicants further propose to restrict the divestiture of peaking, mid-merit, and coal capacity by not allowing more than 25% of the capacity (i.e. 1,375 MW) to be sold in the aggregate to a market participant that holds between 3% and 5% of the total installed capacity in either the PJM East or the Expanded PJM markets.

**What general concerns do you have with the interim mitigation proposal?**

The interim mitigation plan proposes that nuclear units be bid at zero. One would be led to believe that the bid levels for nuclear units are important for market power considerations, but in fact this is not the case given market dynamics in PJM. Prices are rarely set at the levels bid by nuclear units. In fact, in 2004, prices were above the marginal cost levels of nuclear units over 95% of the time. Nuclear units would typically reap the profit of strategic behavior by other units, rather than be used to raise prices. Hence, nuclear units' contribution to market power is in terms of operation not pricing. Whether the Applicants bid the nuclear units at $0 or at their marginal cost of approximately $10/MWh, the impact on profits to the Applicants' portfolio is inconsequential. In fact, bidding in these units at $0 will only guarantee that they maximize their output, which will improve the profitability of the strategic behavior in which the other units engage. The Commission should require the Applicants to enter into firm, long-term contracts (of energy and capacity) or divest outright the nuclear units. For a more robust interim solution, the Commission could require the Applicants to propose bid caps for the other assets that are more likely to be price setting.

In addition, the virtual divestiture of baseload nuclear units involves energy-only commitments. In order to help eliminate screen failures in the PJM Capacity Credit market, the virtual divestitures may need to be adapted to include capacity rights as well as energy rights to the output of the nuclear plants. The Applicants' proposed fix for the shortfall in mitigation quantities is to bid the lesser of 2,400 MW or the net UCAP position less 100 MW at $0 into the PJM Capacity Credit auctions. To the extent that the Applicants have any residual that they will be able to bid above $0 in the markets, then the zero price offer strategy will not ameliorate market power concerns.

**What general concerns do you have with the proposed long-term mitigation plan?**

The Applicants have earmarked 5,500 MW to be divested in order to cure the Economic Capacity screen failures. In doing so, they propose to treat each MW as identical in terms of its contribution to reducing market power in the energy market. This is not correct: one MW from a coal plant is not equivalent to one MW from a gas-fired plant, in terms of price-setting, profitability, and thus market power potential. Coal plants and other baseload units that are infra-marginal are typically the 'breadwinners' in a portfolio. Their objective is to maximize output so as to ensure operation through all the high-price periods. Peaking capacity, on the other hand, will be the price setter and will be used to implement a particular price increase strategy. If there are many peaking plants in a portfolio, it is much more profitable for a portfolio owner to divest some surplus peaking capacity than to divest baseload capacity. Furthermore the divestiture of a peaking plant is unlikely to have the same impact in reducing market power potential as the divestiture of a coal or nuclear unit.

For example, if we were aiming to cure a screen failure for Economic Capacity under a Destination Market Price of $60/MWh, a coal plant (with dispatch costs in the $35/MWh to $45/MWh range) would be the preferred candidate over a gas-fired plant (with a dispatch cost of $70/MWh to $80/MWh) at prevailing gas prices because the coal plant is 'economic'. Dr. Hieronymus has tried to take this into account, but he has calibrated his analysis to three Destination Market Price levels per season (four categories for the summer season). Withholding and pricing up strategies are most profitable when they coincide with points of discontinuity on the supply curve. Dr. Hieronymus may have not identified all the points on the supply curve that lend themselves to market power manipulation. Without substantial sensitivity analyses, we cannot say with certainty that the proposed mitigation is sufficient and suitable.

This issue of interchangeability is especially evident when considering ancillary services markets, where certain generation may simply not have the necessary technology or capability. Again, let us take the coal and gas plant analogy as an example. A coal plant may not have the required flexibility (due to ramp rates) to provide spinning reserves whereas a quick-start gas-fired GT may be better equipment to participate in the spinning reserve market. Unless the technical qualifications of the 5,300 MW slated for divestiture are identified, the FERC will not be able to evaluate the Applicants' proposed mitigation plan.

The Applicants also propose to reduce their baseload mitigation commitment by future transmission expansion projects into PJM East. Dr. Hieronymus states in his testimony that "mitigation will continue subject to the condition that the virtual divestiture requirement will be extinguished, megawatt for megawatt, to the extent that the Applicants' PJM East nuclear capacity is decommissioned, derated or sold, and to the extent that new transmission capacity is constructed."[40] Though I agree with the basic premise of adjusting the mitigation amounts for any outright sales, I strongly disagree with the hypothesis that transmission and generation should be treated as substitutes. While transmission and generation may be substitutes in some circumstances, they are not perfect substitutes under real world conditions. A baseload nuclear plant will operate around the clock at close to its full rated capacity while a transmission line will carry flows of different magnitudes, depending on the demand for transmissions services, but also possibly the state of the transmission network elsewhere in the system.

Transmission capacity (bundled with transmission rights) can also be used to enhance market power in generation. And, if transmission is well-placed to reduce market power - it may not necessarily work on a one MW to one MW basis with generation. The Commission must consider the Applicants' request carefully. Given the uncertainties regarding the timing, location, and impact of new infrastructure on system dynamics, I do not think that the FERC can reasonably agree to this request today. The FERC will want to perform or direct the

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[40] Application, Exhibit J-1 at 8.

Applicants to perform incremental analyses, if and when transmission expansion occurs, in order to determine its impact on mitigation requirements.

In summary, capacity is not interchangeable and certain assets may be more important than others in price setting and in the exercise of market power. In order for the FERC to adequately consider the Applicants' proposed mitigation, the Applicants must identify the plants to be divested. Furthermore, the Applicants are obligated to do this under the FERC's own guidelines for remedial action. For example, the FERC notes in its *Merger Policy Statement* that "remedial commitments must specify exactly which facilities are affected by the commitment, e.g., which generating unit(s) will be divested."[41]

I also believe that the virtual auction process needs to be further detailed. The Applicants have not addressed critical issues with respect to long-term contracting. For example, what will be the back-stop remedies if the virtual contracts do not sell? What will happen if there is a default on these contracts in the future? In addition, a closer inspection of the terms of the contracts is necessary to ensure that no residual incentive mechanisms exist to reduce the value of such mitigation measures. Unless solutions to these problems are defined today, FERC may risk unleashing substantial market power onto the PJM marketplace in the future.

The Applicants should also be required to demonstrate that the restrictions they have placed on potential buyers will facilitate competition in the wholesale market and in the auction

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[41] FERC. 18 CFR PART 2 (Docket No. RM96-6-000). "Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement" ORDER NO. 592. (Issued December 18, 1996), pg. 83.

process. Those qualified to participate in the auction process will be limited to small tranches of the divested capacity. Given minimum efficient scale of plant operations and financing and the maximum purchase limits proposed by the Applicants (725 MW if market share is under 3% to 1,450 MW if market share is under 5%), the physical divestiture auctions may not be successful due to diseconomies of scale.

Lastly, the Applicants do not propose any structural safeguards to deal with future expansion of the PJM portfolio, possibly through acquisitions or new construction. Expansion of generation may occur in the course of normal business. For example, the Applicants may seek to expand their nuclear capacity or build on brownfield sites they own. Mitigation measures should address this potential development.

**What concerns do you have with the proposed mitigation plan in the context of your independent Competitive Analysis Screen?**

The proposed mitigation by the Applicants is not sufficient to cure all the screen failures in my Competitive Analysis Screen of Economic Capacity (for the energy market). Based on the screen failures in my Delivered Price Test, another 390 MW of mid-merit divestitures are warranted for PJM East (raising the total amount of divestitures to 5,690 MW), while Expanded PJM has mid-merit mitigation needs of 890 MW in addition to the 5,500 MW already earmarked by the Applicants. My sensitivity analysis however suggests that additional mitigation requirements may be as high as 960 MW for PJM East, yielding a total mitigation amount in this scenario of over 6,260 MW (versus the 5,300 MW proposed by the Applicants).

I also had screen failures in the Competitive Analysis Screen for PJM's Capacity Credit market. Total mitigation of 4,201 MW to 7,550 MW of capacity is warranted for Expanded PJM on the basis of my tests results. PJM East's capacity market - if one develops - would require mitigation in the range of 5,385 MW to 5,621 MW. Notably, the capacity mitigation aligns well with the 5,690 MW of total mitigation recommended in the energy market Competitive Analysis Screen. This kevel of mitigation would be feasible if the Applicants would modify their virtual divestiture process to include capacity on top of energy.

Other tests for possible market power reveal similar concerns. Even with the Applicants' proposed mitigation plan, the MBR market share screen of the generation market power tests under Section 205 of the FPA will be exceeded. Our analysis indicates 3,000 additional MW would need to be divested to bring the test metrics in compliance with the FERC's 20% threshold for Expanded PJM. A market-based rate authorization request would presumably be filed before the merger is completed; hence, I believe it is relevant for the purposes of analyzing market power potential in the context of this merger proceeding, especially as the Commission has recognized the influence that market-based rate authority has on market power incentives.

Furthermore, the Applicants' mitigation measures are not sufficient to cure the high concentration levels achieved under the Concentration Test for Spare Capacity or to eliminate the possibility of higher prices through coordinated action. Additional peaking capacity would need to be divested to cure the screen failures in this test.

**What are your recommendations to the Commission on the proposed mitigation plan?**

Based on the combined analysis of market power discussed above, I believe that the quantity and quality of the proposed mitigation measures are not adequate. Indeed, given the uncertainty regarding the plants that will actually be sold and the details of the virtual divestitures, the FERC may not want to formulae and finalize a mitigation plan until a full record is developed at hearing.

Based on my preliminary quantitative analysis and modeling and review of the information provided by the Applicants and their technical witnesses, I recommend that, at the very least, the proposed mitigation plan be adjusted along the following lines:

- Applicants to increase total capacity divested from 5,500 MW to 6,400 MW in Expanded PJM (and an increase of 400 MW to 5,700 MW in PJM East), in order to protect against the screen failures in my independent analysis of Economic Capacity;

- Applicants to modify the virtual divesture auction plans to include long-term rights to capacity as well as energy so as to ensure sufficient capacity-related mitigation, which will allow the Applicants to meet the capacity screen failures more easily (additional capacity right divestitures of approximately 1,100 MW of may nevertheless be necessary in Expanded PJM, above and beyond the 6,400 MW of divestitures we are proposing above);

- Applicants to prepare contingency protocols and substantial long-term structural safeguards in case of contract default (with respect to the virtual divestitures) or internal capacity expansion;

- Applicants to file a list of assets to be divested for FERC review and approval;

- Applicants to file contract documents for virtual divestitures for FERC review and approval; and
- Applicants to file auction protocols and rules for FERC review and approval.

**Does this conclude your testimony?**

Yes.

**UNITED STATES OF AMERICA**
**BEFORE THE**
**FEDERAL ENERGY REGULATORY COMMISSION**

Commonwealth of Massachusetts )
) ss.
County of Essex )

**AFFIDAVIT OF JULIA FRAYER**

I, Julia Frayer, being duly sworn, depose and state that the statements contained in the testimony and exhibits of Julia Frayer, are true and correct to the best of my knowledge, information and belief.

Julia Frayer

SUBSCRIBED AND SWORN TO BEFORE ME, this the 11th day of April, 2005.

Notary Public, Commonwealth of Massachusetts

# 6 Exhibits

## Exhibit 1: Resume for Julia Frayer

### KEY QUALIFICATIONS:

Julia Frayer joined London Economics' Boston office in February 1998. As a Principal at London Economics International LLC, Julia has worked extensively in the US, Canada, Europe, and Asia on various infrastructure related projects, including valuation advisory and negotiations, regulation and market design, and strategic positioning.

As head of the regulatory economics practice at London Economics, Julia is very involved in market power issues. In January 2005, she testified on a FERC Technical Panel on the subject mater of market power testing and mitigation as it relates to FERC's interim screens for generation market power in market-based rate authorization proceedings. She has also prepared the market power analysis for several successful market-based rate applications subsequently to FERC's April 2004 Order modifying the indicative screens for generation market power analysis. Currently, she is advising the Alberta Department of Energy on market power regulation in Alberta after the expiration of the current holding restrictions. As part of this engagement, she has helped designed an innovative ex post test of market prices for evidence of market power rents. She is also advising participants in ERCOT on horizontal market power issues in electricity generation, including market power definition and use of efficient market power testing regimes.

Prior to joining London Economics, Julia was working as an Investment Banker with Merrill Lynch in New York. At Merrill Lynch, she specialized in the financial sector, working closely with specialty finance companies, re-insurance firms, asset management and regional depository institutions, in both mergers and acquisitions aspect and strategic financing areas.

### EDUCATION:

Graduate School of Arts & Sciences, Boston University (1996-97) **M.A.** in Economics

College of Arts & Sciences, Boston University (1994-97) **B.A.**, Summa Cum Laude, in Economics and International Relations, member of Phi Beta Kappa

### EXPERIENCE:

The projects briefly described below are typical of the work Julia has performed throughout her career at London Economics:

- *Advisory to the Alberta Department of Energy on market power safeguards for the Alberta electricity sector:* As part of the London Economics team, Julia managed the theoretical analysis and quantitative simulation modeling in the design and testing of recommended new regulatory regime. Analysis and recommendations will be presented to stakeholders in the spring of 2005.

- *Economic analysis and expert testimony in front of the Public Utilities Commission of Texas on market power related issues:* prepared and filed testimony and quantitative analysis on questions of market definition and market integration. In 2003, also provided testimony on pricing safeguards proceeding, which looked at alternative market power testing procedures for market power, analyzed implications on investment, and disused efficiency consequences of certain bidding behavior.

- *Contract analysis and risk management:* Julia led analysis of large market participants' collar contract positions within its overall portfolio-wide risk management strategy in Northeast market. Analysis and risk management recommendations will be presented to Board of Directors.

- *Preparation of analysis for generation market power under FERC's indicative screens:* In support of various acquisitions by major international power companies the Northeast announced in 2004, Julia has prepared and continues to be involved in expert testimony for Market-based Rate Authorization applications, Triennial Reviews, and Section 203 filings.

- *Market analysis and forecasting for IPP developer in Ontario in response to Ministry of Energy's RFEI for 2,500 MW of clean energy:* Julia directed the quantitative analysis and wholesale electricity price forecasting completed for a IPP. Projections were used to justify project sponsorship of a small gas-fired plant in front of the IPP's Board of Directors and led to project submission to RFEI. In addition, Julia and her team of economists designed a risk model for the client to evaluate the contract payment risks vis-à-vis actual dispatch.

- *Resource adequacy workshop:* Julia co-presented at an IPPSA-sponsored workshop in Alberta on resource adequacy market institutions, specifically speaking to the installed capacity and locational installed capacity markets implement in the US among certain Northeastern ISOs.

- *Econometric analysis of the elasticity of demand for transmission services between Canadian provinces and US markets in the Northeast:* Julia led the economic analysis for an IPP investigating the impact on trade from increased transmission costs, involving multi-factor regression analysis of nodal electricity prices, price spreads across markets, and interchange flows (imports and exports) across borders. Analysis will be used as evidence in a regulatory hearing for proposed tariff changes.

- *Monitoring of 5,500 MW RFP for energy services for standard offer contract issued by Connecticut-based utility:* the Department of Public Utility Control of Connecticut retained the services of LEI to assist the DPUC in monitoring the power procurement processes for Connecticut Light & Power's (CL&P) Transitional Standard Offer auction in

November 2004 for services in 2005 and 2006. Julia led LEI's team in providing advisory services to the DPUC, including guidance on communications protocols, design of sales contract agreement (between CL&P and winning bidders), and also valuation of final bids vis-à-vis the forward market alternatives available to the utility. Julia filed an affidavit after completion of the process which the Commissioners used to approve the process and the contracts between CL&P and the winning bidders.

- *Economic advisory on market power mitigation tests:* for a large US-based utility in the Southwestern part of the US, consulting on market design features related to a proposed nodal market, including most significantly the market power analysis framework. LEI proposed strategy and is assisting in the development of an implementation framework for the local market, including prepared reports for the market design team and state commission. In addition, the approach will be proposed for federal review at FERC.

- *Analysis of LMPs in New England:* using well-established econometric techniques, analyze location-based marginal prices in New England since inception of the new nodal system. Assess the node-specific marginal loss and congestion premiums for certain assets located in load pockets. Analysis integral to a valuation of a portfolio of generation assets and power supply agreements.

- *Valuation of a pumped storage facility:* in support of an asset bid by a multi-national player, Julia and her team of economists and modelers completed a medium-term analysis of potential peak versus off-peak price trends in a key Eastern Interconnect market. The price forecast was based on both network simulations using marginal cost-based bidding and strategic bidding. The strategic biding analysis was based on an innovative algorithm, referred to as ConjectureMod, developed by LEI in consultation with a well-known game theorist in electric power markets.

- *Extensive economic support of a private client's acquisition of a New England-based generating portfolio:* as part pf an on-going engagement, Julia is assisting a large Canadian private client in its acquisition of a large New England generation portfolio. Julia and her team supported the client's valuation team, providing extensive forecasting and revenue modeling support for the bid development, due diligence, and cost-benefit analysis of key components of the portfolio (which contains an assortment of power plants, ranging from coal-fired facilities to hydro units, and other power sector-related assets, such as transmission rights contracts, power purchase agreements, and power supply obligations). London Economics, with Julia's support, is currently working on FERC filings in anticipation of the acquisition, which will assess the market power attributes of the transaction, per Section 203 requirements. In addition, London Economics'' quantitative and modeling analysis will be used to support securitization and credit rating efforts which may include the acquired assets.

- *Development of a methodology for transmission assessment for the CA ISO:* LEI was engaged by the California Independent System Operator (CA ISO) to construct a framework for the economic valuation of transmission investment. Though grounded in a cost-benefit analysis approach, the methodology is moved beyond traditional valuation frameworks to incorporate concepts from real options investment analysis and game theory, and include innovative techniques for forecasting market power implications for wholesale power markets. In the last phase, LEI demonstrated the practical application of the methodology to a real-world transmission investment. The work, completed jointly with the CAISO, was filed with the CPUC in late 2002. As a result of this work, LEI developed a linear program model, which combined with econometric techniques, which helped resolve and evaluate the question of generation and transmission interdependence.

- *Support the Balancing Pool on economic issues related to the MAP II sale of dispatch rights associated with key generation assets currently controlled by the Balancing Pool:* conducted an in-depth analysis of current and future market outcomes under a variety of ownership structures (required multi-year simulation modeling of strategic behavior using CUSTOMBid) for energy and ancillary services market in Alberta, quantitative analysis served as foundation for the design of efficient holding restrictions that would be applied to the sale of the Clover Bar, Sheerness, and Genesee contracts; consulted the Balancing Pool, MAP Committee, and associated parties on sale process and auction design principles; provided an independent valuation of the contracts using an options-based approach based on London Economics' proprietary spark-spread model.

- *Valuation of international transmission project*: using a real options application involving locational price spreads, designed specifically for this engagement, Julia and her team of economists quantified the congestion rents expected to be earned by the developer of an international transmission line in North America and thus evaluated the private benefits to the transmission owner.; financial model constructed for developer to use in analyzing economics of the project on an on-going basis, in order to win Board approval and negotiate risk-sharing contract terms with co-sponsor.

- *Preparation of valuation for a successful bid in a generation auction in Ontario:* Julia assisted in the valuation of the Mississauga hydro portfolio. Economic analysis involved the use of LEI's market power analysis (using London Economics' proprietary game theoretic model of strategic behavior), LEI's production cost-based simulation software, POOLMod, and London Economics' tailored real options-based approach for hydro assets. As part of this engagement, LEI staff participated in the initial round analysis, aided in the due diligence process, and consulted the client on second-round bidding.

- *Market study of the Southeast US and projection of power purchase options for a 400-MW load facility siting at the cross-roads of several Midwest and Southeast markets (SERC, SPP, MAIN, and MAPP regions):* in advising a large industrial customer on its power supply options (buy or build) over the medium-term, LEI conducted a joint economic and technical study of the power markets and transmission systems in the Southeast market; Julia coordinated the engineering assessment, involving extensive analysis of the security of the transmission grid through load flow analysis and contingency tests. Economic analysis build upon the transmission topography defined in the technical assessment and provided the client with a medium-term independent outlook on wholesale energy prices for the market, based on regional configuration and realities of the transmission system in this part of the country. LEI's POOLMod production cost simulation software used to complete the forecast.

- *Economic feasibility study of a New York City cogeneration facility, a Western New York peaker, New York City CCGT (various clients)*: for a developer, prepared a ten-year revenue forecast for a proposed cogeneration facility, including a forecast of energy and capacity revenues (namely intrinsic revenues) and a volatility or real options-based adder (extrinsic revenues) for the New York City zone of the NY ISO. Analysis was used in support of board approval and aided in the design of the project (e.g., choice of technology and flexibility of such technology vis-à-vis expected market outcomes). For another private client, conducted a longer term projection (spanning 20 years) for a peaking power generation project in Western New York, producing a forecast for regional energy, installed capacity, options-based adders, and ancillary services revenues streams.

- *Implementation of real options modeling framework:* conducted numerous valuation exercises using real options-based framework for generation assets and transmissions rights for a variety of engagements, including asset valuation, and structuring of transmission rights portfolio.

- *Valuation of Mid-Atlantic utility (private client), 2001:* co-led economic aspect of valuation process for potential acquisition of Mid-Atlantic utility for international entity. Analysis included valuation of PJM-based generation portfolio through the use of production cost-based models and real options applications. Julia also coordinated evaluation effort for trading entity and regulated asset base (wires assets), including review of exposure due to provider of last resort obligations. Julia and her team of economists assessed contract portfolio and load growth parameters, as well as mitigation measures employed by target utility.

- *Modeling of the future value of emissions reduction credits in regional, continental and global emissions trading markets:* on behalf of large multinational client, Julia completed a study of the short to long term dynamics of the emissions trading markets. The majority of the focus was on greenhouse gas emissions and the potential for tradeable instruments in North America based on recent publicized transactions and pilot trading programs. However, discussion of current US emissions trading markets (for nitrogen oxide and sulfur dioxide) and their relative features was included in the report.

- *Valuation of Ontario generating facilities, including assessment of regional electricity markets:* organized and implemented major modeling effort to determine potential value of generation stations in Ontario. Assessed impact of transmission constraints and restructuring efforts in neighboring markets on future wholesale market prices; forecast competitive market price for Ontario over the long term with detailed review of market dynamics and key price formation drivers; projected the reaction of key market players and the implications of their actions of market prices over the near term utilizing proprietary game theoretic model.

- *Measurement of contract exposure under a series of PPA contracts and its effect on enterprise value:* this study was done in conjunction with a due diligence process, where London Economics was part of team analyzing a potential merger between an international power producer and diversified US utility. In identifying key issues in merger between these two entities, London Economics was given the task of defining and quantifying the liabilities associated with the US utilities' power purchase agreements. Julia lead the analysis on behalf of London Economics in the due diligence process: constructing a theoretical framework and applying it to complex asset swap and power purchase agreements in order to measure the magnitude of the liability via current and forecasted market conditions.

- *Surveyed the current US environmental regulatory framework for international client and produced detailed compliance cost analysis for US generation asset operators:* investigated current and future policy guidelines (including stay of OTAG program by Federal Courts), outlined key regulation and emission protocols under EPA's Acid Rain Program, Ozone Transport Regulation and New Source Review, measured the cost of compliance options for US generators through analysis of forecasted allowance prices, and the cost of technological mitigation implementation (BACT) and other emissions reducing initiatives (e.g. coal switching, operational guidelines). As a final product, Julia authored a working paper that laid out the multiple layers of environmental regulation for generators in the US with a detailed case study, defining the technological and cost impacts of this regulation on one large US utility.

- *Review of market dynamics in the California market as part of generation asset valuation:* London Economics was hired by leading financial institutions to review the long term energy, ancillary services, and capacity price forecasts for Southern California and resulting revenues for a set of assets that were undergoing debt financing. As part of this investigation, Julia drafted a critique of the proposed price forecast and suggested methodology improvements and a set of alternative price benchmarks for debt financing valuation purposes.

- *Valuation of distribution assets:* quantified synergies and developed strategies for potential cross-border transaction between top Canadian distribution corporation and affiliate of Top 20 US utility, by performing in-depth analysis of diversified strategies available to global energy companies in energy generation, transmission, distribution, wholesale and retail marketing, energy services, and other infrastructure industries. Julia co-managed a team of economists and consultants, pursuing unique valuation approaches in this transaction, utilizing comparable analysis, examination of PRB mechanisms and other regulatory pricing designs, growth strategies, as well as the application of real options theory.

- *Midwest price forecasting:* Julia headed the analysis of long-term price forecasts for the Midwest US (ECAR, MAIN, and MAPP); managing a team of economists in their effort to establish fifteen-year energy and capacity price forecasts for several US regions. As part of the modeling effort, London Economics proprietary dispatch simulation model, POOLMOd, was used, in conjunction with a competitive capacity-pricing module. The long-term modeling effort required detailed investigation of the micro and macro-economic issues facing these regional markets: demand profiling, growth forecasting, reserve margin and new entry activity assessment. This analysis was used by a client in establishing market values for assets they have targeted to acquire over the medium-term.

- ***Completed initial modeling and organized competitive market analysis tutorial for the staff of the Italian Energy Regulatory Authority:*** worked with the regulatory advisors to the Italian government in their on-going effort to restructure the power sector in Italy. Julia, as part of an international team of economists consulting the regulator, led the competitive market modeling tutorial. She advised IERA staff on the use of London Economics' proprietary pool simulation model in assessing the current issues in the Italian generation market (such as potential market power problems) and market conditions after privatization/divestiture.

- ***Valuation of coal-fired generation assets in the NYPP:*** forecast energy and capacity prices for the New York market on a sub-regional basis, rooted in transmission constraint parameters. Utilizing London Economics' proprietary pool simulation model, Julia composed detailed unit-by-unit performance, revenue and cost parameters over the next twenty years. In addition, she investigated the affect on market projections by varying key drivers and scenario assumptions, in an effort to bracket the perceived risks to clients. Julia studied the influence of several key market drivers, such as the implementation of various environmental programs, changes to system supply-demand profile due to various new entry/retirement profiles, modification of market rules, and shifts in key input markets (e.g. coal, natural gas and oil markets).

- ***Valuation of New England, PJM and Midwest generation assets:*** evaluated potential value of assets available under various regional auctions for a dominant IPP player. Julia worked with client in composing a bid proposal by assessing market risks posed by various factors, such as fuel price shifts, merchant plant construction scenarios, site conversion potential, and transmission constraints and through extensive production cost modeling.

## PUBLICATIONS AND SPEAKING ENGAGEMENTS:

Frayer, Julia "Written Statement of Julia Frayer for the January 27th 2005 Technical Conference in Docket RM04-7-000" Panelist, *FERC Technical Conference*, Washington D.C., January 27, 205.

Frayer, Julia "Competitive procurement options for Ontario's LDCs" Speaker, *APPrO 2004 Conference*, Toronto, Ontario (Canada), November 24, 2004.

Frayer, Julia, Nazli Uludere, and Sam Lovick "Beyond market shares and cost plus pricing: designing a horizontal market power mitigation framework for today's electricity markets." *Electricity Journal*, November 2004.

Frayer, Julia "The World Changed on August 14th: the (Second) Great Northeast blackout." Chairman of Panel Session, *Electric Power Conference* 2004, Baltimore, Maryland, March 30, 2004.

Frayer, Julia "Alternative to LMP pricing for transmission: a case study of the ICRP approach used by National Grid Company in the UK." Speaker, *Electric Power Conference* 2004, Baltimore, Maryland, March 31, 2004.

Frayer, Julia "Big ticket leasing - what next for the future?" Panelist, *Big Ticket Leasing 2003*, London (United Kingdom), March 12, 2003.

Frayer, Julia "Evaluating the Electron Highway" Speaker, *IPPSO 2001 Conference*, Richmond Hill, Ontario (Canada), November 28, 2001.

Frayer, Julia and Nazli Uludere "What is it worth? Application of real options theory to the valuation of generation assets" *Electricity Journal*, November 2001.

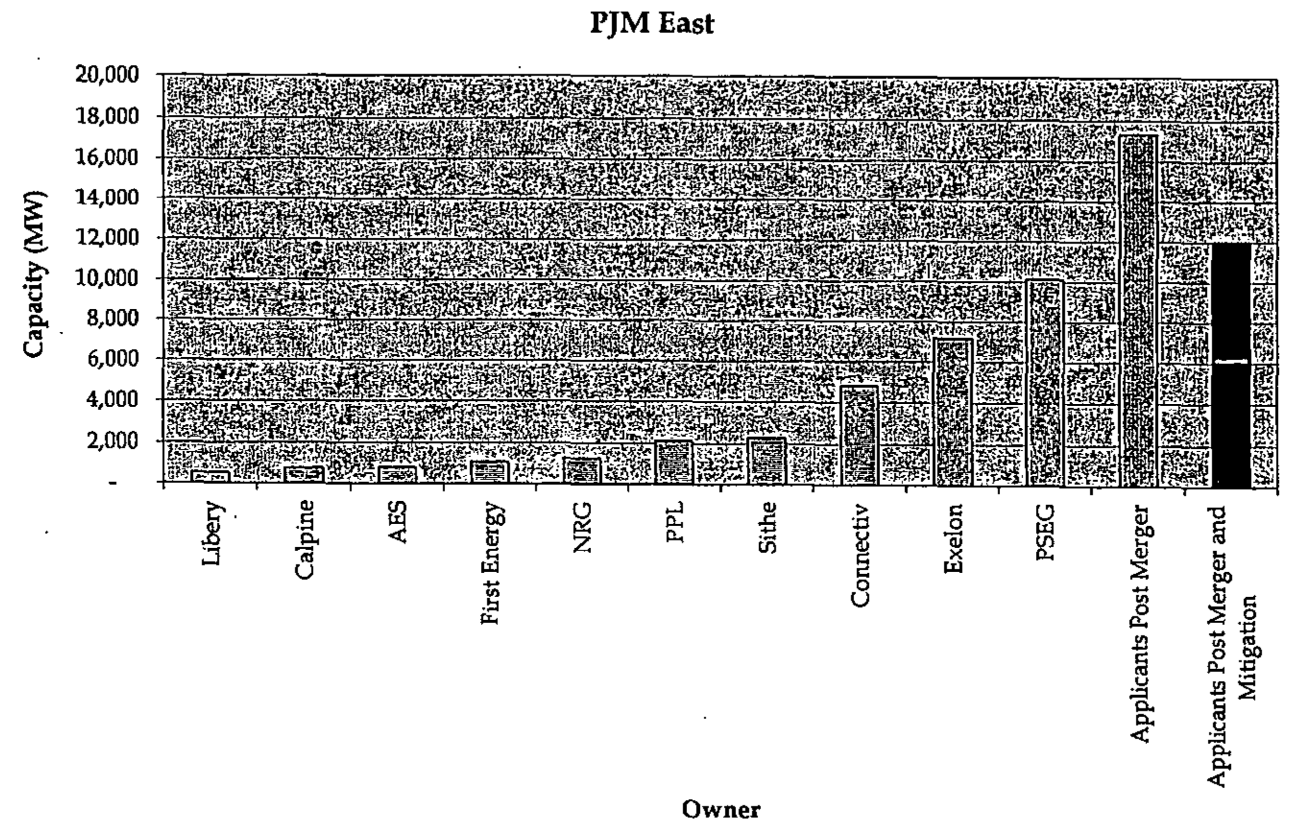
Goulding, A.J., Julia Frayer, Jeffrey Waller "*X Marks the Spot*: How UK Utilities Have Fared Under Performance-Based Ratemaking" *Public Utilities Fortnightly*, July 15, 2001.

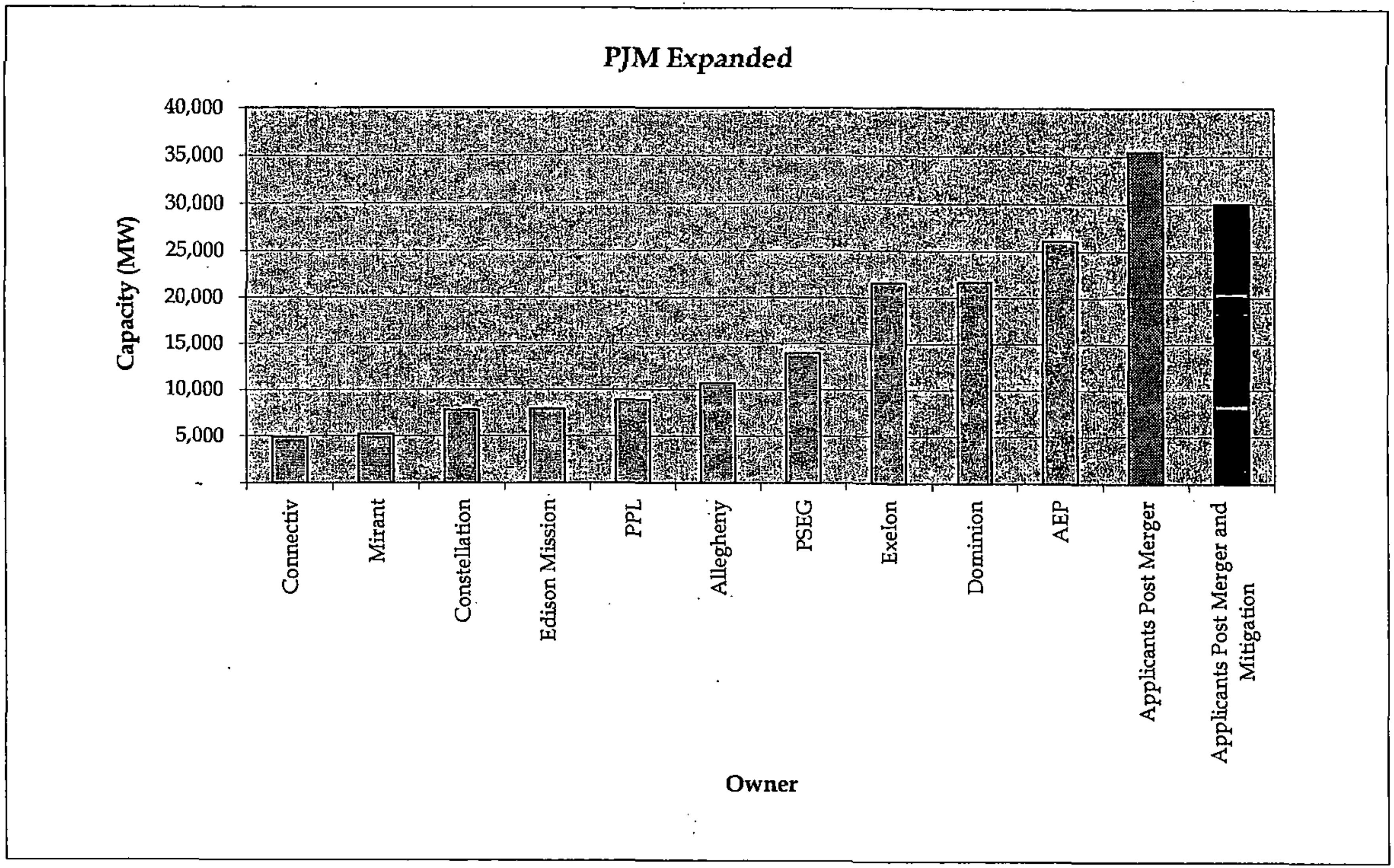
Frayer, Julia "How much is it worth? Applying real options valuation framework to generation assets" Speaker, *Electric Power 2001*, Baltimore, Maryland, March 22, 2001.

Goulding, A.J., Julia Frayer, Nazli Z. Uludere "Dancing with Goliath: Prospects After the Breakup of Ontario Hydro" *Public Utilities Fortnightly*, March 1, 2001.

Frayer, Julia and William Chapman "Improving price forecasting in wholesale power markets through the application of models of strategic bidding" Speaker, *EPRI International Pricing Conference 2000*, Washington, D.C., July 28, 2000.

## Exhibit 2: Capacity of the top ten players and the Applicants

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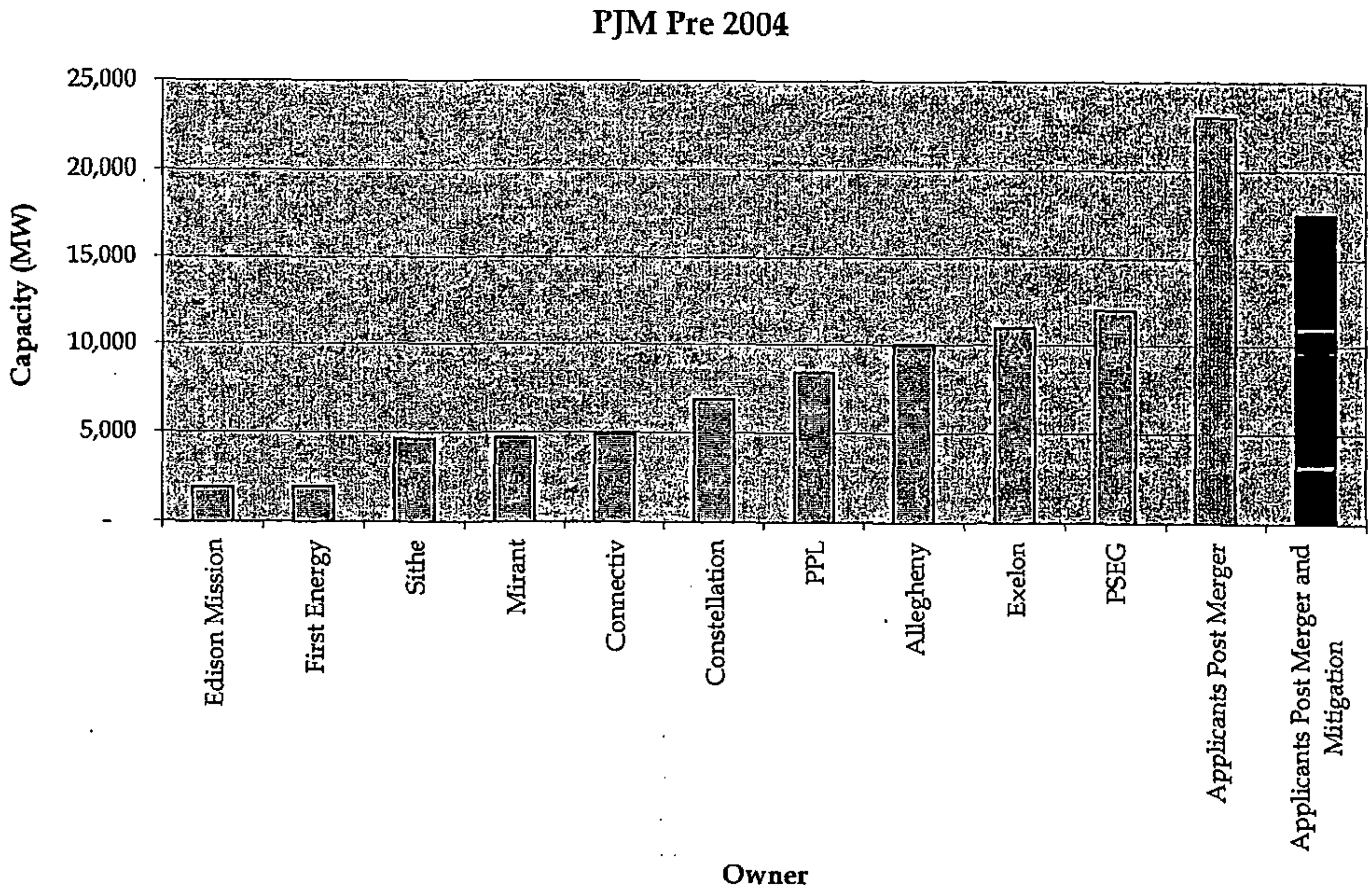
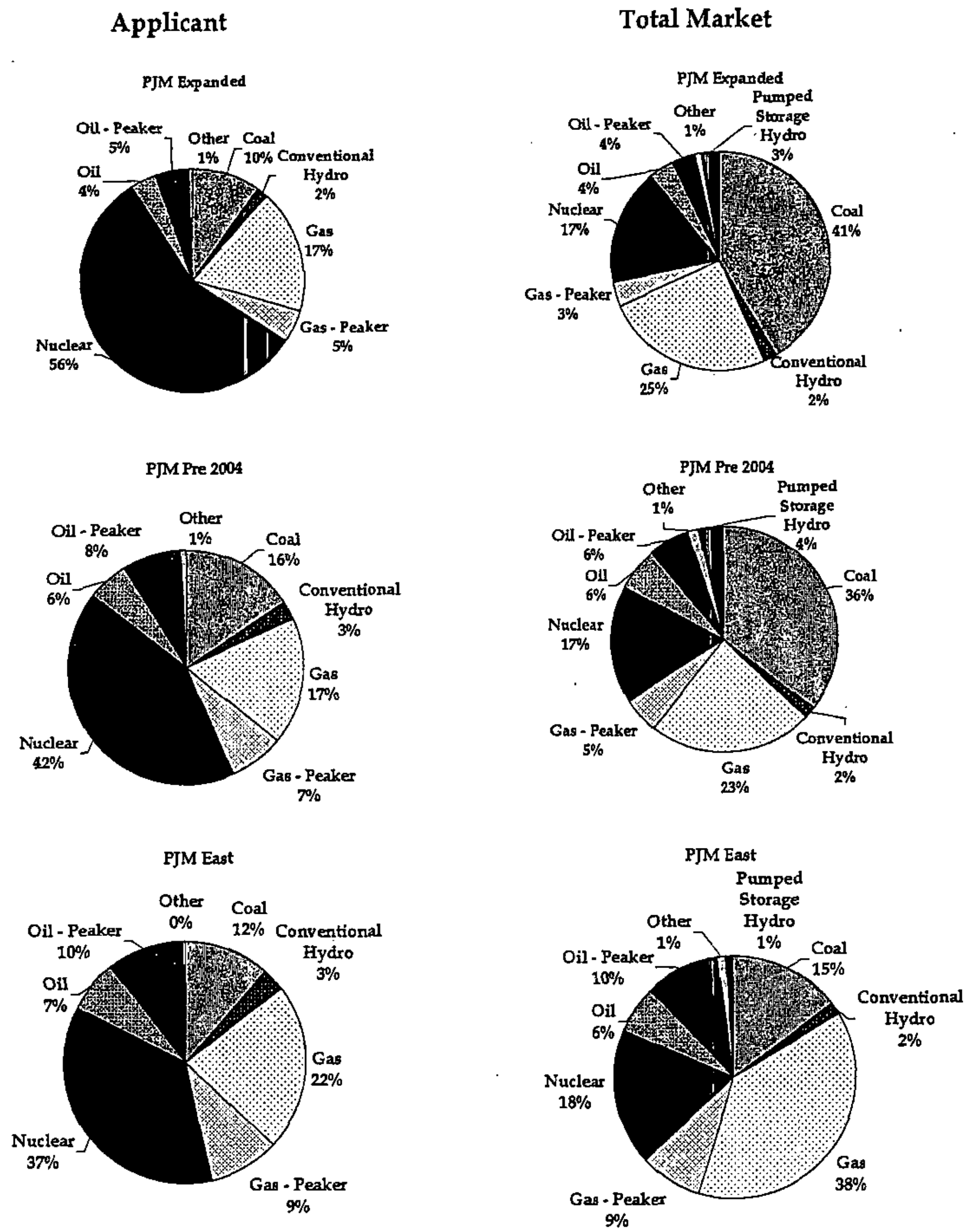
Owner



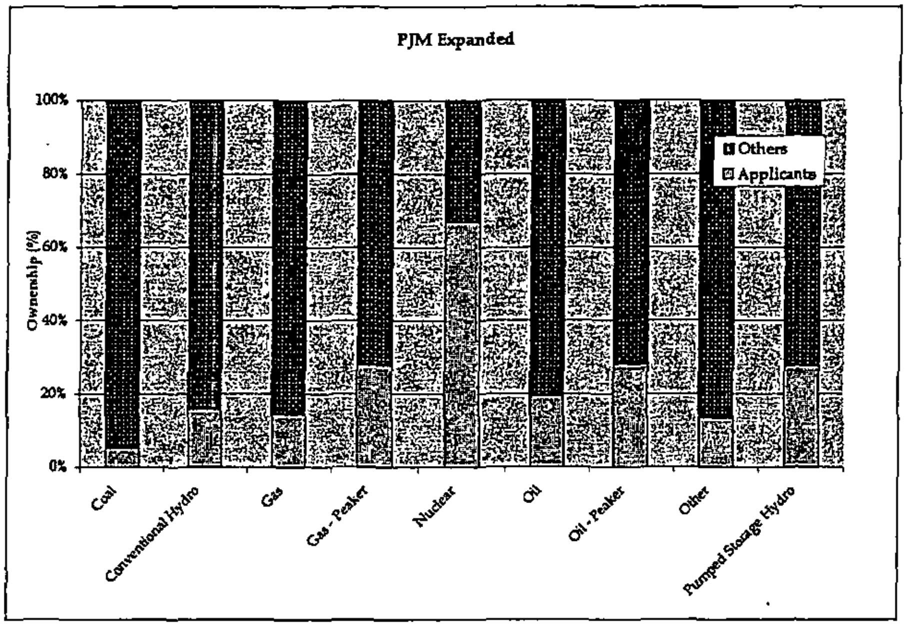


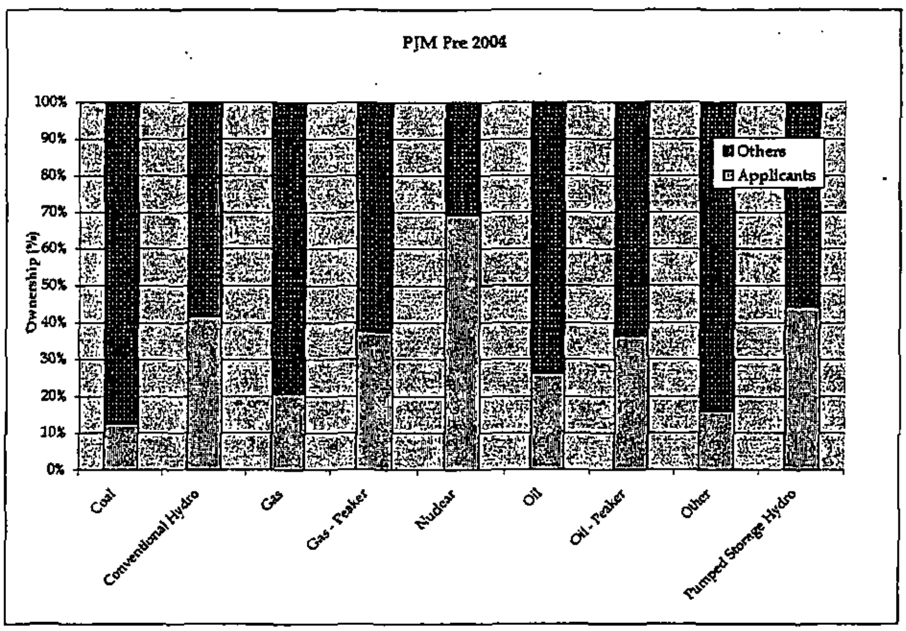
London Economics International LLC
717 Atlantic Ave, Unit 1A
Boston, MA 02111
www.londoneconomics.com

## Exhibit 3: Capacity by fuel type for the market and the Applicants

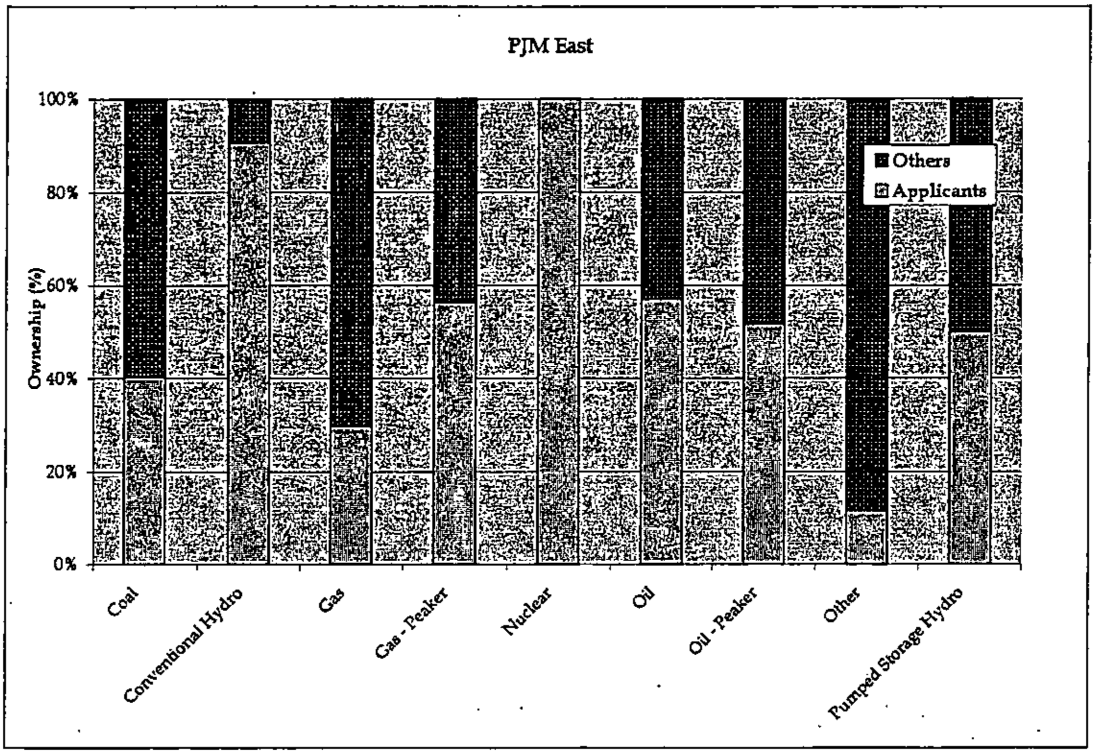


## Capacity by fuel type post merger



**Capacity by fuel type post merger (continued)**





London Economics International LLC
717 Atlantic Ave, Unit 1A
Boston, MA 02111
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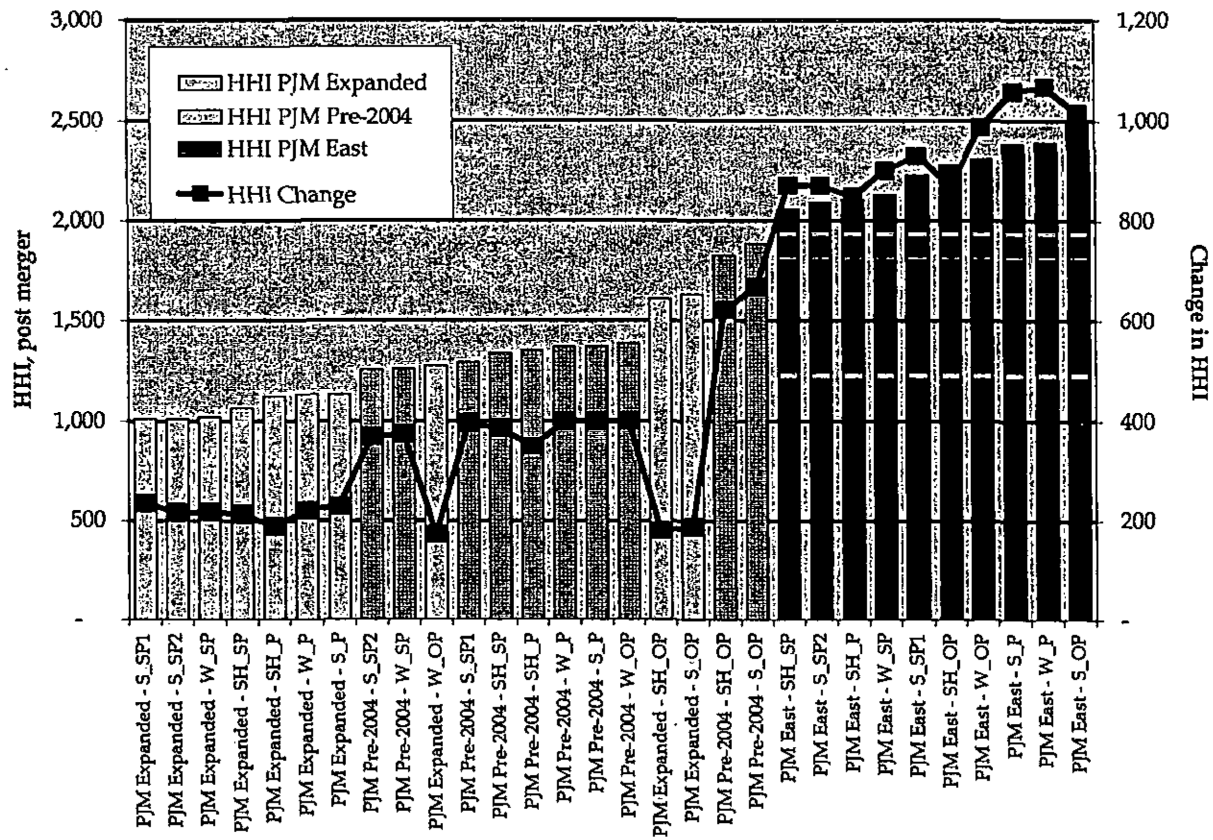
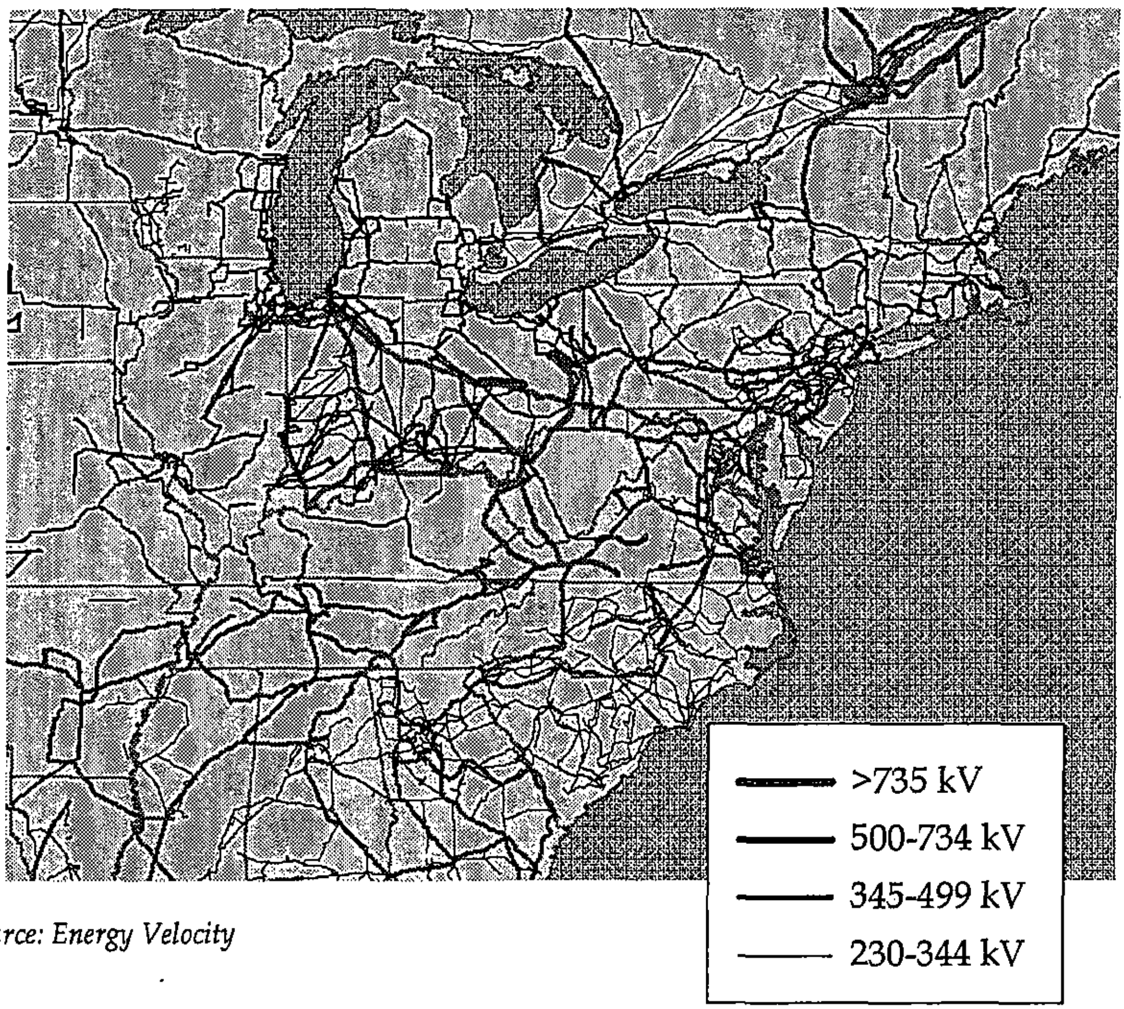
## Exhibit 4: Economic Capacity HHIs - Dr. Hieronymus



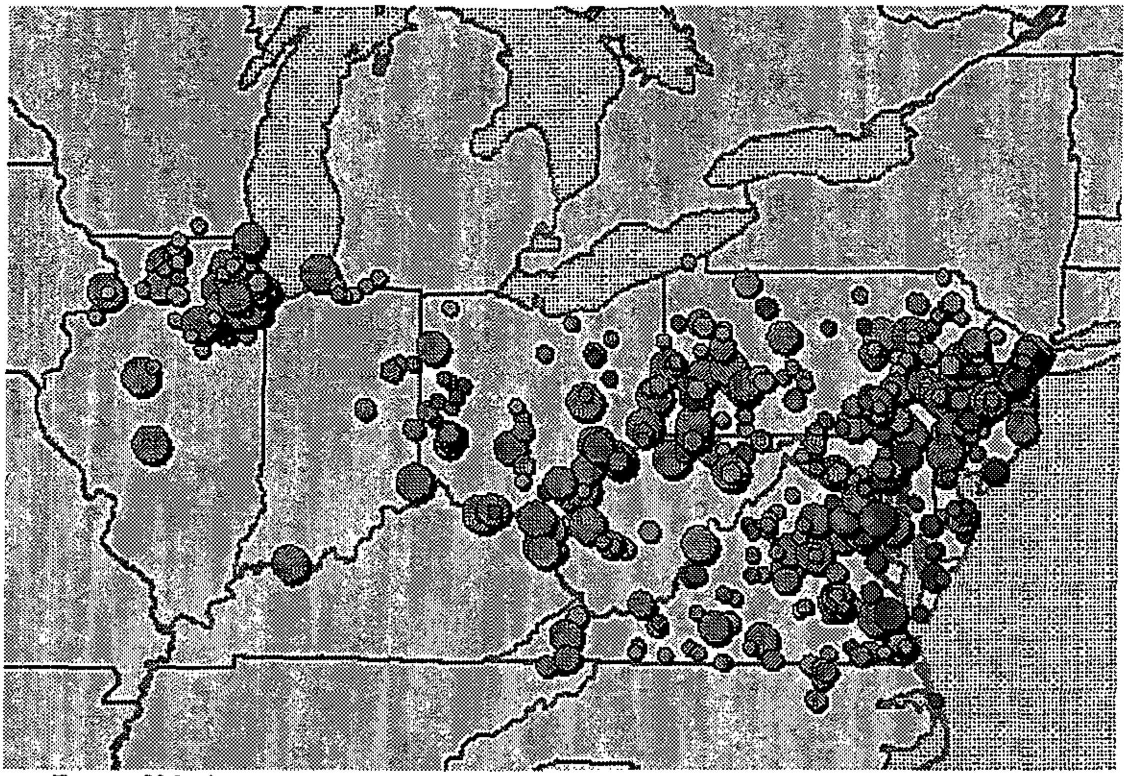
## Exhibit 5: Map of the Expanded PJM market

**Transmission infrastructure in Expanded PJM**

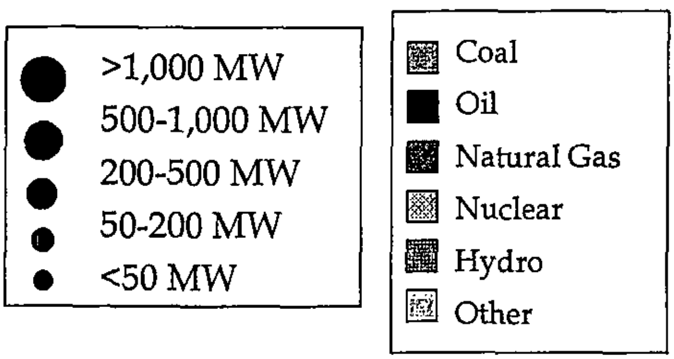



*Source: Energy Velocity*

**Generation plants in Expanded PJM**



*Source: Energy Velocity*



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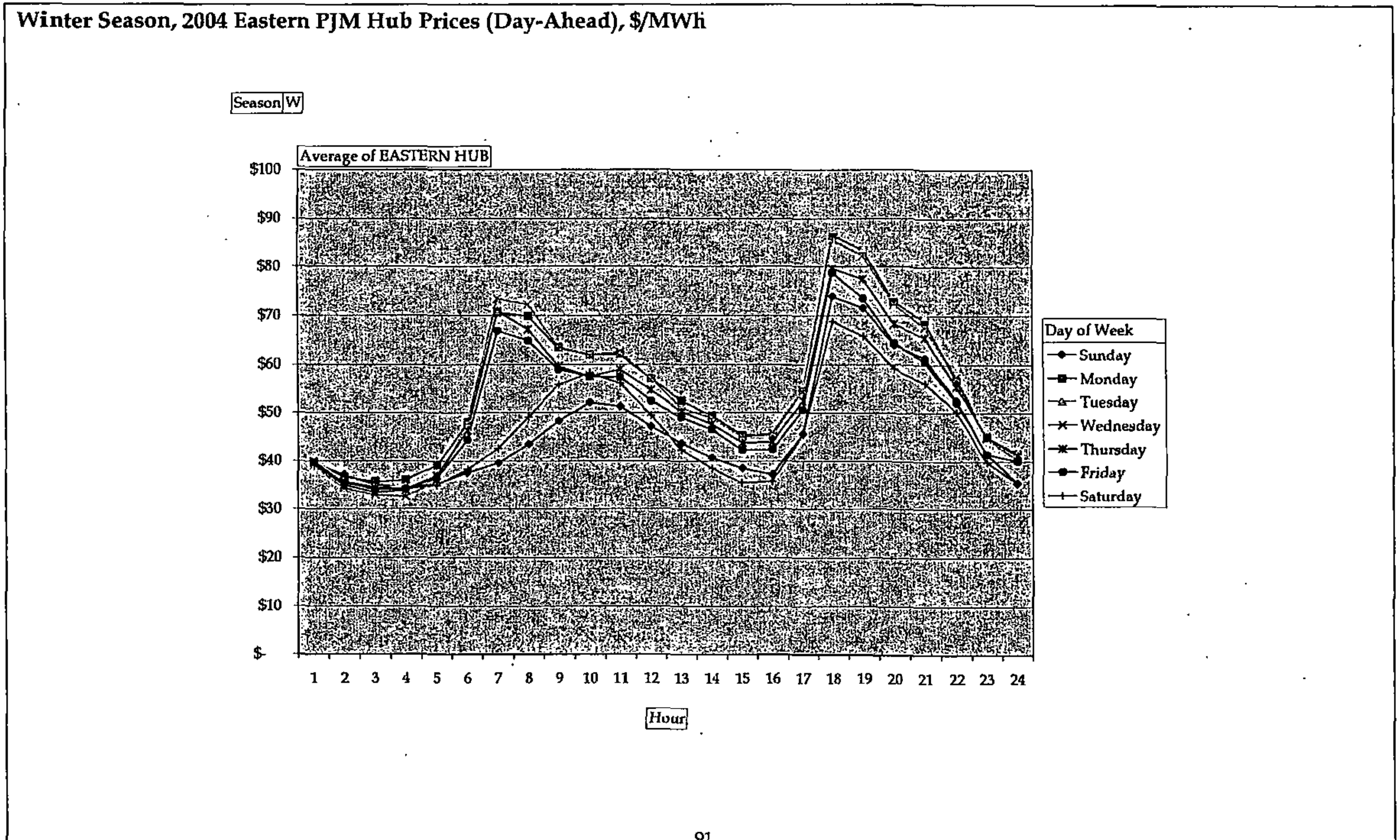
## Exhibit 6: Historical price profiles by season - 2004



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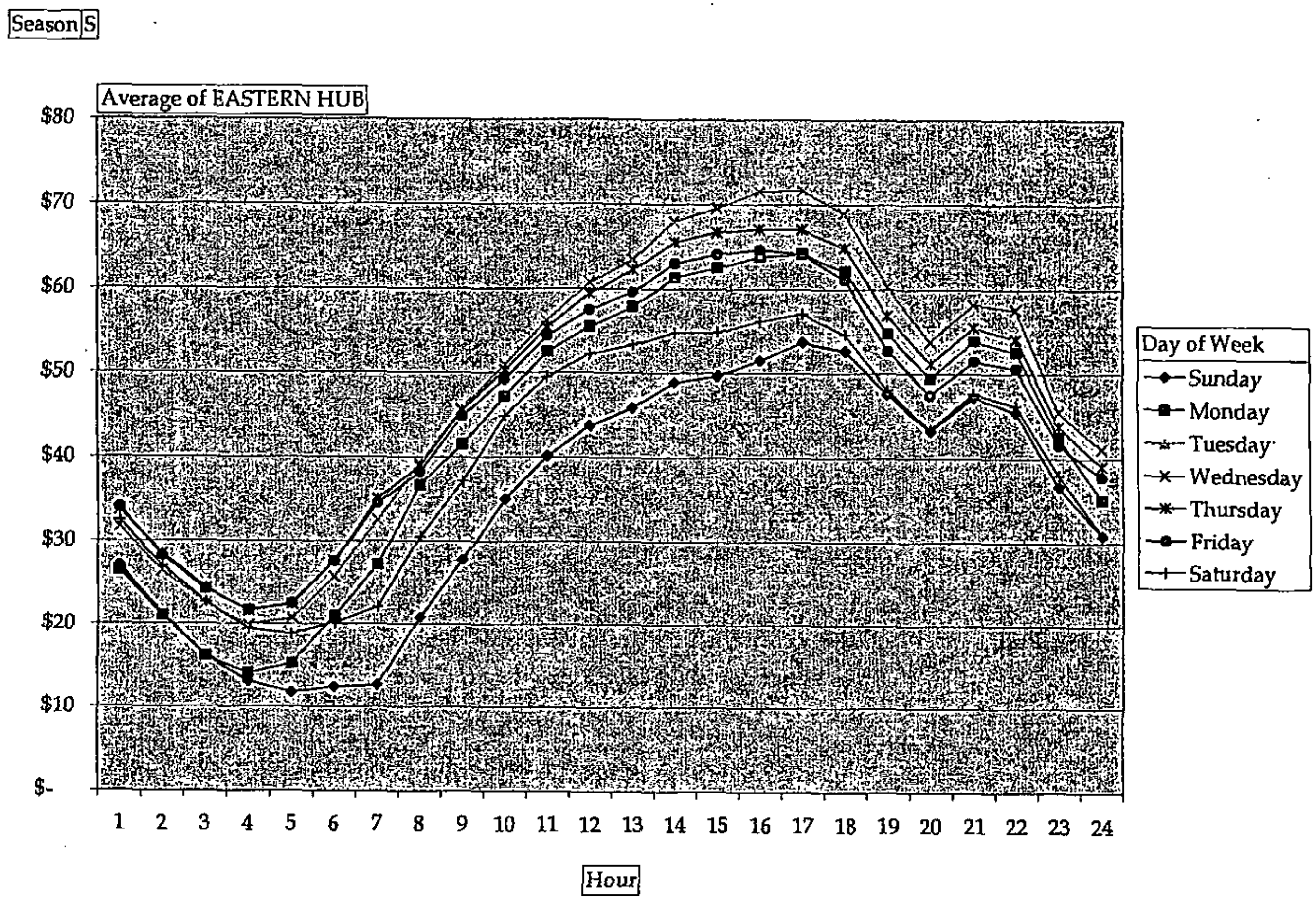
**Summer Season, 2004 Eastern PJM Hub Prices (Day-Ahead), $/MWh**



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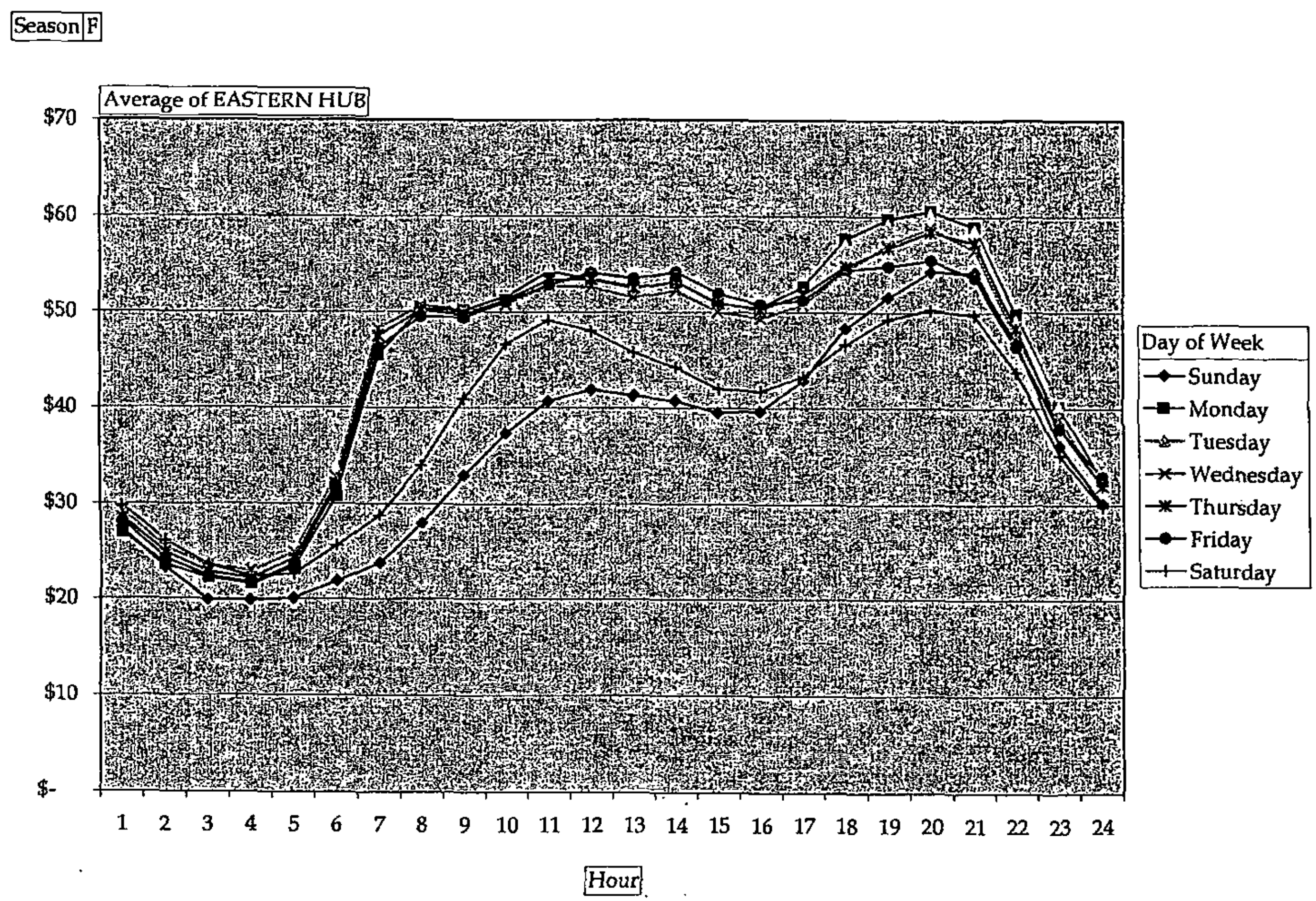
**Fall Season, 2004 Eastern PJM Hub Prices (Day-Ahead), $/MWh**





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# Exhibit 7: Projected fuel prices used in LEI's Delivered Price Test

| | | | Delivered Natural Gas Prices (2006 $/MMbtu) | | |
|---|---|---|---|---|---|
| | | | Winter | Summer | Shoulder |
| Commodity Price | | Henry Hub | $8.49 | $7.30 | $7.59 |
| *Destination market* | *States* | *Trading Hub* | | | |
| PJM Control Area | DC | Tetco M3 | $10.91 | $7.86 | $8.19 |
| PJM Control Area | DE | Tetco M3 | $10.91 | $7.86 | $8.19 |
| PJM Control Area | IL | Chicago Citygate | $8.02 | $7.33 | $7.52 |
| PJM Control Area | IN | Chicago Citygate | $8.02 | $7.33 | $7.52 |
| PJM Control Area | KY | Dominion | $9.25 | $7.78 | $8.06 |
| PJM Control Area | MD | Transco Z6 | $12.12 | $7.84 | $8.18 |
| PJM Control Area | MI | Chicago Citygate | $8.02 | $7.33 | $7.52 |
| PJM Control Area | NC | Dominion | $9.25 | $7.78 | $8.06 |
| PJM Control Area | NJ | Tetco M3 | $10.91 | $7.86 | $8.19 |
| PJM Control Area | OH | Dominion | $9.25 | $7.78 | $8.06 |
| PJM Control Area | PA | Transco Z6 | $12.12 | $7.84 | $8.18 |
| PJM Control Area | TN | Tennessee Zone 0 | $8.04 | $7.11 | $7.34 |
| PJM Control Area | VA | TCO | $8.85 | $7.65 | $7.97 |
| PJM Control Area | WV | Dominion | $9.25 | $7.78 | $8.06 |
| *First-tier markets* | *States* | | | | |
| NYISO | NY | NY Citygate | $10.90 | $7.86 | $8.19 |
| TVA | - | Tennessee Zone 0 | $8.04 | $7.11 | $7.34 |
| Duke | - | TCO | $8.85 | $7.65 | $7.97 |
| CPL (Progress) | - | TCO | $8.85 | $7.65 | $7.97 |
| MISO | - | Chicago Citygate | $8.02 | $7.33 | $7.52 |

| | | | Delivered Coal Prices (2006 $/MMbtu) | | |
|---|---|---|---|---|---|
| | | | Winter | Summer | Shoulder |
| Commodity Price | | Sandy River | $4.93 | $4.76 | $4.78 |
| *Destination market* | *States* | | | | |
| PJM Control Area | DC | | $5.43 | $5.30 | $5.32 |
| PJM Control Area | DE | | $5.43 | $5.30 | $5.32 |
| PJM Control Area | IL | | $4.76 | $4.62 | $4.65 |
| PJM Control Area | IN | | $4.88 | $4.71 | $4.73 |
| PJM Control Area | KY | | $4.91 | $4.73 | $4.75 |
| PJM Control Area | MD | | $5.08 | $4.97 | $5.24 |
| PJM Control Area | MI | | $5.05 | $4.86 | $4.87 |
| PJM Control Area | NC | | $5.46 | $5.31 | $5.33 |
| PJM Control Area | NJ | | $5.53 | $5.29 | $5.29 |
| PJM Control Area | OH | | $4.93 | $4.76 | $4.78 |
| PJM Control Area | PA | | $4.93 | $4.84 | $4.86 |
| PJM Control Area | TN | | $4.96 | $4.86 | $4.85 |
| PJM Control Area | VA | | $5.25 | $5.05 | $5.11 |
| PJM Control Area | WV | | $4.97 | $4.81 | $4.82 |
| *First-tier markets* | *States* | | | | |
| NYISO | NY | | $5.06 | $5.07 | $5.02 |
| TVA | TN | | $4.96 | $4.86 | $4.85 |
| Duke | average NC/SC | | $5.39 | $5.23 | $5.25 |
| CPL (Progress) | average NC/SC | | $5.39 | $5.23 | $5.25 |
| MISO | average MI/WI/IL/IN/OH/KY | | $4.89 | $4.72 | $4.74 |

| | | | Delivered FO#2 Prices (2006 $/MMbtu) | | |
|---|---|---|---|---|---|
| | | | Winter | Summer | Shoulder |
| Commodity Price | | New York Harbor | $11.65 | $10.87 | $11.19 |
| *Destination market* | *States* | *Rack Rate Location* | | | |
| PJM Control Area | DC | Baltimore, MD | $13.90 | $13.12 | $13.44 |
| PJM Control Area | DE | Wilmington, DE | $14.78 | $14.00 | $14.32 |
| PJM Control Area | IL | Chicago Citygate | $13.25 | $12.47 | $12.79 |
| PJM Control Area | IN | Chicago Citygate | $13.25 | $12.47 | $12.79 |
| PJM Control Area | KY | Knoxville, TN | $14.19 | $13.41 | $13.74 |
| PJM Control Area | MD | Baltimore, MD | $13.90 | $13.12 | $13.44 |
| PJM Control Area | MI | Chicago Citygate | $13.25 | $12.47 | $12.79 |
| PJM Control Area | NC | Charlotte, NC | $14.11 | $13.33 | $13.66 |
| PJM Control Area | NJ | Newark, NJ | $14.00 | $13.22 | $13.55 |
| PJM Control Area | OH | Aurora, OH | $14.30 | $13.52 | $13.84 |
| PJM Control Area | PA | Altoona, PA | $14.35 | $13.57 | $13.89 |
| PJM Control Area | TN | Knoxville, TN | $14.19 | $13.41 | $13.74 |
| PJM Control Area | VA | Norfolk, VA | $13.61 | $12.82 | $13.15 |
| PJM Control Area | WV | Montvale, VA | $13.97 | $13.19 | $13.51 |
| *First-tier markets* | *States* | | | | |
| NYISO | NY | New York, NY | $14.29 | $13.50 | $13.83 |
| TVA | - | Knoxville, TN | $14.19 | $13.41 | $13.74 |
| Duke | - | Charlotte, NC | $14.11 | $13.33 | $13.66 |
| CPL (Progress) | - | Charleston, SC | $14.23 | $13.45 | $13.78 |
| MISO | - | Chicago Citygate | $13.25 | $12.47 | $12.79 |

| | | | Delivered FO#6 Prices (2006 $/MMbtu) | | |
|---|---|---|---|---|---|
| | | | Winter | Summer | Shoulder |
| Commodity Price | | New York Harbor | $8.03 | $7.98 | $7.89 |
| *Destination market* | *States* | *Rack Rate Location* | | | |
| PJM Control Area | DC | Baltimore, MD | $9.22 | $8.82 | $8.82 |
| PJM Control Area | DE | Wilmington, DE | $8.98 | $8.49 | $8.51 |
| PJM Control Area | IL | Philadelphia, PA | $9.00 | $8.60 | $8.61 |
| PJM Control Area | IN | Philadelphia, PA | $9.00 | $8.60 | $8.61 |
| PJM Control Area | KY | Norfolk, VA | $9.04 | $8.66 | $8.66 |
| PJM Control Area | MD | Baltimore, MD | $9.22 | $8.82 | $8.82 |
| PJM Control Area | MI | Philadelphia, PA | $9.00 | $8.60 | $8.61 |
| PJM Control Area | NC | Wilmington, NC | $8.78 | $8.45 | $8.44 |
| PJM Control Area | NJ | New York, NY | $9.31 | $8.92 | $8.90 |
| PJM Control Area | OH | Philadelphia, PA | $9.00 | $8.60 | $8.61 |
| PJM Control Area | PA | Philadelphia, PA | $9.00 | $8.60 | $8.61 |
| PJM Control Area | TN | Norfolk, VA | $9.04 | $8.66 | $8.66 |
| PJM Control Area | VA | Norfolk, VA | $9.04 | $8.66 | $8.66 |
| PJM Control Area | WV | Norfolk, VA | $9.04 | $8.66 | $8.66 |
| *First-tier markets* | *States* | | | | |
| NYISO | NY | New York, NY | $9.31 | $8.92 | $8.90 |
| TVA | TN | Norfolk, VA | $9.04 | $8.66 | $8.66 |
| Duke | - | Wilmington, NC | $8.78 | $8.45 | $8.44 |
| CPL (Progress) | - | Wilmington, NC | $8.78 | $8.45 | $8.44 |
| MISO | - | Philadelphia, PA | $9.00 | $8.60 | $8.61 |

## Exhibit 8: Destination Market Price for 2006 ($/MWh)

| Season | Period | Pre-2004 PJM and Expanded PJM | PJM East |
|---|---|---|---|
| Summer | Extreme Peak | $113 | $125 |
| Summer | Top 10% of Peak | $84 | $87 |
| Summer | Rest of Peak | $65 | $69 |
| Summer | Offpeak | $37 | $41 |
| Winter | Top 10% of Peak | $120 | $123 |
| Winter | Rest of Peak | $76 | $80 |
| Winter | Offpeak | $55 | $63 |
| Shoulder | Top 10% of Peak | $83 | $86 |
| Shoulder | Rest of Peak | $65 | $68 |
| Shoulder | Offpeak | $42 | $45 |

## Exhibit 9: Comparison of Destination Market Price assumptions ($/MWh)

**Expanded PJM / Pre-2004 PJM**

Hieronymus

| | *Winter* | *Summer* | *Shoulder* |
|---|---|---|---|
| *SP2* | | $250 | |
| *SP* | $80 | $80 | $65 |
| *Peak* | $55 | $55 | $45 |
| *Offpeak* | $30 | $25 | $20 |

LEI

| | *Winter* | *Summer* | *Shoulder* |
|---|---|---|---|
| *SP2* | | $113 | |
| *SP* | $120 | $84 | $83 |
| *Peak* | $75 | $65 | $65 |
| *Offpeak* | $55 | $37 | $42 |

% Difference

| | *Winter* | *Summer* | *Shoulder* |
|---|---|---|---|
| *SP2* | | -55% | |
| *SP* | 50% | 5% | 28% |
| *Peak* | 36% | 18% | 44% |
| *Offpeak* | 83% | 48% | 110% |

**PJM East**

Hieronymus

| | *Winter* | *Summer* | *Shoulder* |
|---|---|---|---|
| *SP2* | | $250 | |
| *SP* | $80 | $80 | $65 |
| *Peak* | $55 | $55 | $45 |
| *Offpeak* | $30 | $25 | $20 |

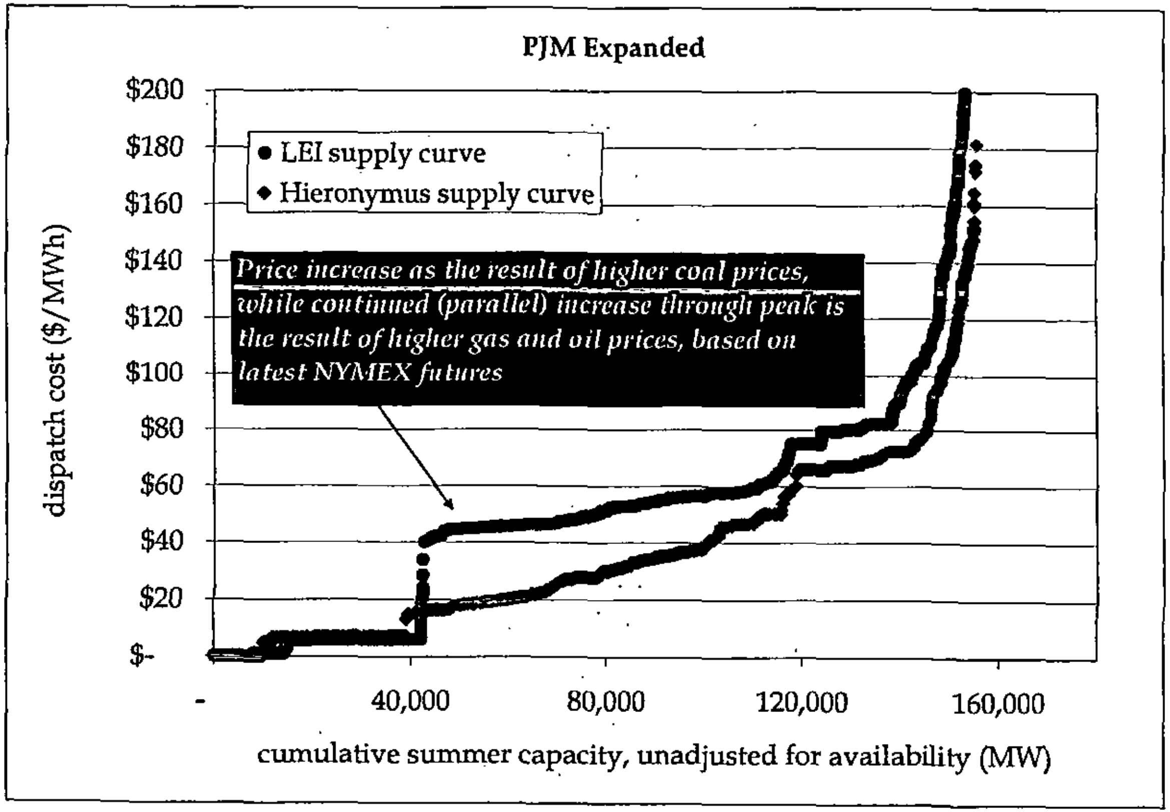
LEI

| | *Winter* | *Summer* | *Shoulder* |
|---|---|---|---|
| *SP2* | | $125 | |
| *SP* | $123 | $87 | $86 |
| *Peak* | $80 | $69 | $68 |
| *Offpeak* | $63 | $41 | $45 |

% Difference

| | *Winter* | *Summer* | *Shoulder* |
|---|---|---|---|
| *SP2* | | -50% | |
| *SP* | 54% | 9% | 32% |
| *Peak* | 45% | 25% | 51% |
| *Offpeak* | 110% | 64% | 125% |

**Exhibit 10: Comparison of supply curves (2006E)**





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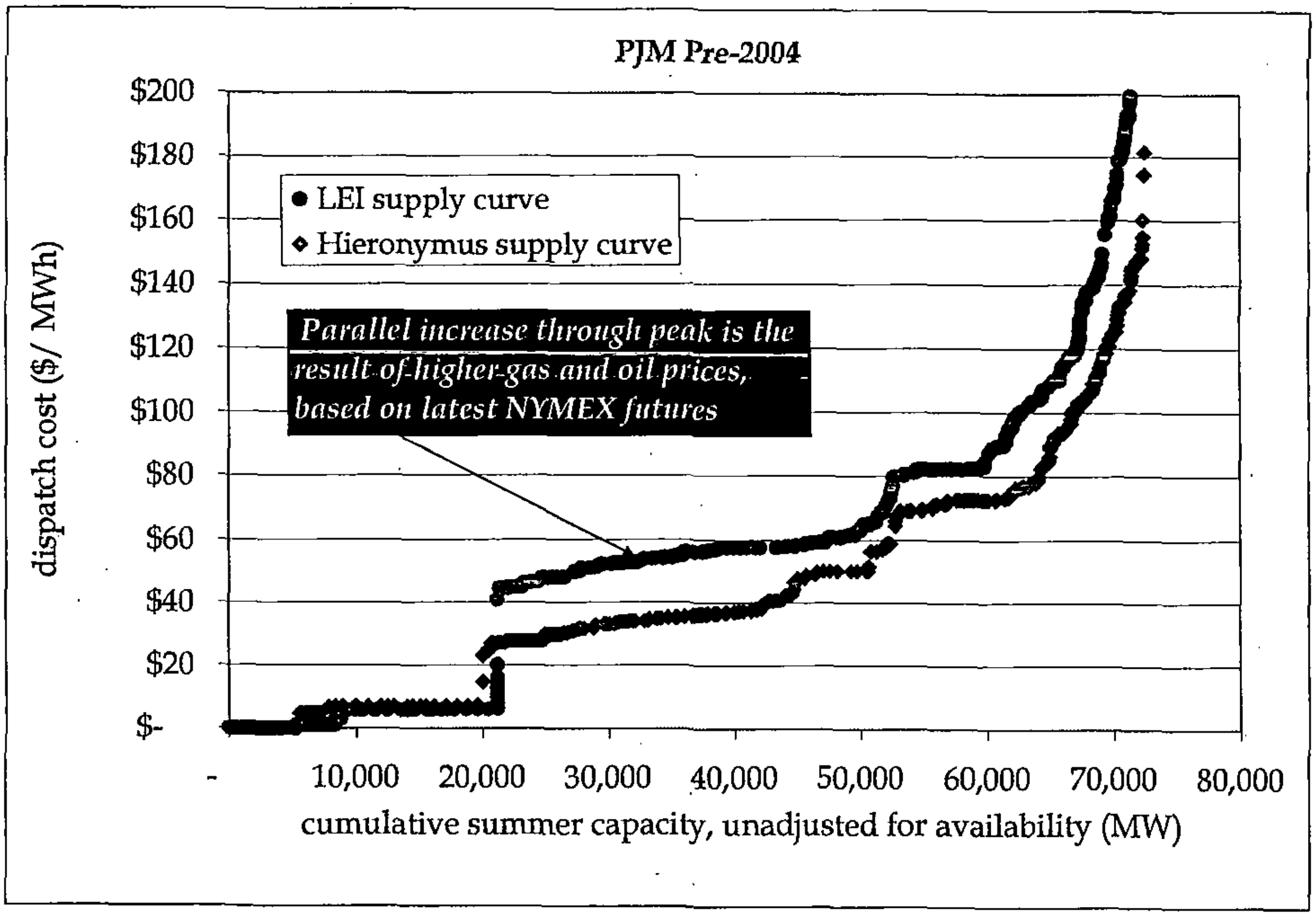
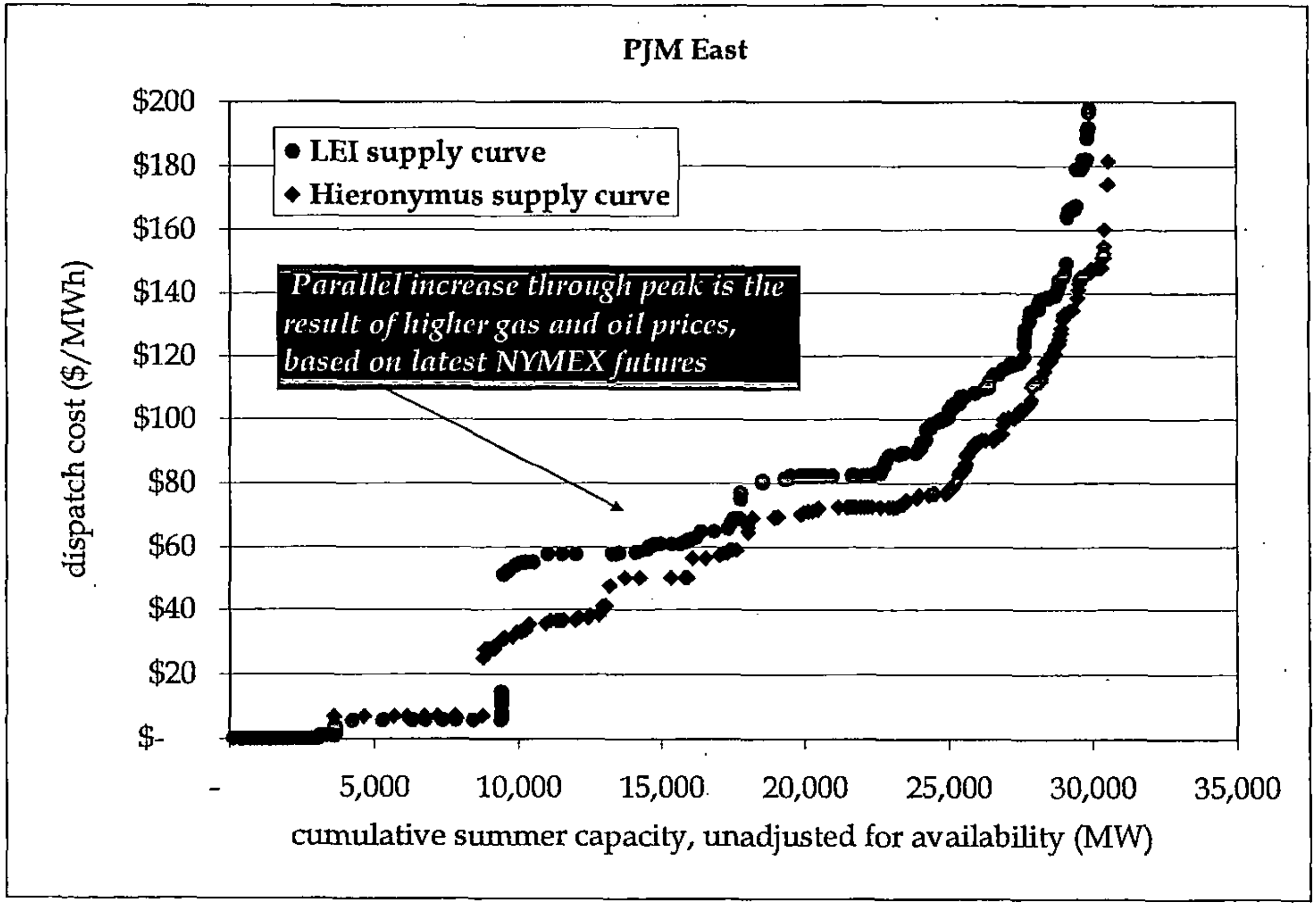

PJM Pre-2004
$200
$180
$160
$140
$120
$100
$80
$60
$40
$20
$-
LEI supply curve
Hieronymus supply curve
Parallel increase through peak is the result of higher gas and oil prices, based on latest NYMEX futures
dispatch cost ($/ MWh)
-
10,000
20,000
30,000
40,000
50,000
60,000
70,000
80,000
cumulative summer capacity, unadjusted for availability (MW)





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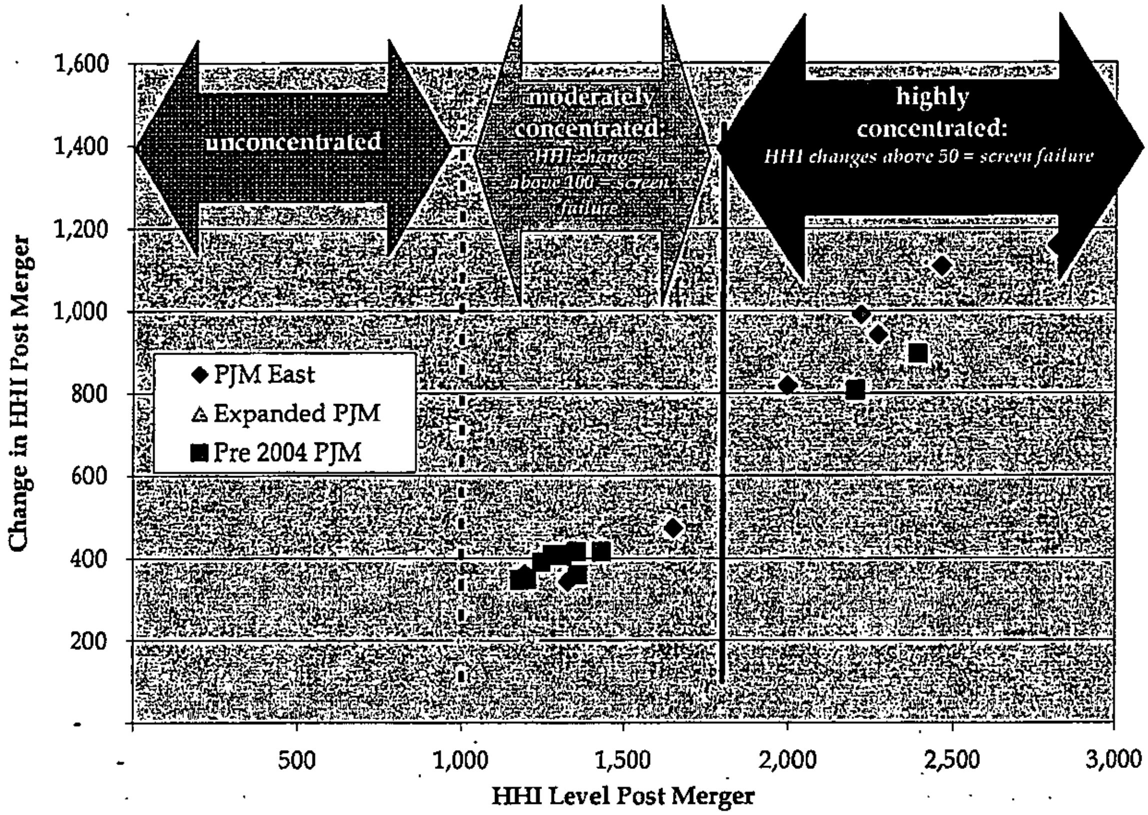
# Exhibit 11: LEI's Economic Capacity HHIs (post-merger)

| PJM Expanded | | | PRE MERGER | | | | | | POST MERGER | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Season | Period | Destination Market Price | Exelon MW | Exelon Market Share | PSEG MW | PSEG Market Share | Market Size | HHI | Merged Entity MW | Merged Entity Market Share | HHI | HHI Change | Status of screen failure? |
| SUMMER | Extreme | $113 | 23,113 | 14.84% | 12,557 | 8.06% | 155,717 | 809 | 35,670 | 22.91% | 1,048 | 239 | Fail |
| SUMMER | Top 10% | $84 | 22,363 | 15.25% | 9,997 | 6.82% | 146,625 | 823 | 32,360 | 22.07% | 1,031 | 208 | Fail |
| SUMMER | Rest of Peak | $65 | 18,683 | 15.49% | 9,368 | 7.76% | 120,650 | 936 | 28,051 | 23.25% | 1,176 | 240 | Fail |
| SUMMER | Offpeak | $37 | 15,319 | 34.76% | 3,192 | 7.24% | 44,070 | 1,584 | 18,511 | 42.00% | 2,088 | 504 | Fail |
| WINTER | Top 10% | $120 | 23,634 | 15.25% | 11,368 | 7.33% | 154,996 | 824 | 35,002 | 22.58% | 1,048 | 224 | Fail |
| WINTER | Rest of Peak | $76 | 19,019 | 16.12% | 8,093 | 6.86% | 118,003 | 990 | 27,112 | 22.98% | 1,211 | 221 | Fail |
| WINTER | Offpeak | $55 | 18,361 | 17.43% | 4,946 | 4.70% | 105,316 | 1,080 | 23,307 | 22.13% | 1,244 | 164 | Fail |
| SHOULDER | Top 10% | $83 | 19,274 | 15.33% | 8,098 | 6.44% | 125,707 | 792 | 27,372 | 21.77% | 989 | 198 | Pass |
| SHOULDER | Rest of Peak | $65 | 15,729 | 15.63% | 7,522 | 7.48% | 100,607 | 902 | 23,251 | 23.11% | 1,135 | 234 | Fail |
| SHOULDER | Offpeak | $42 | 13,530 | 31.42% | 2,728 | 6.34% | 43,059 | 1,342 | 16,257 | 37.76% | 1,740 | 398 | Fail |

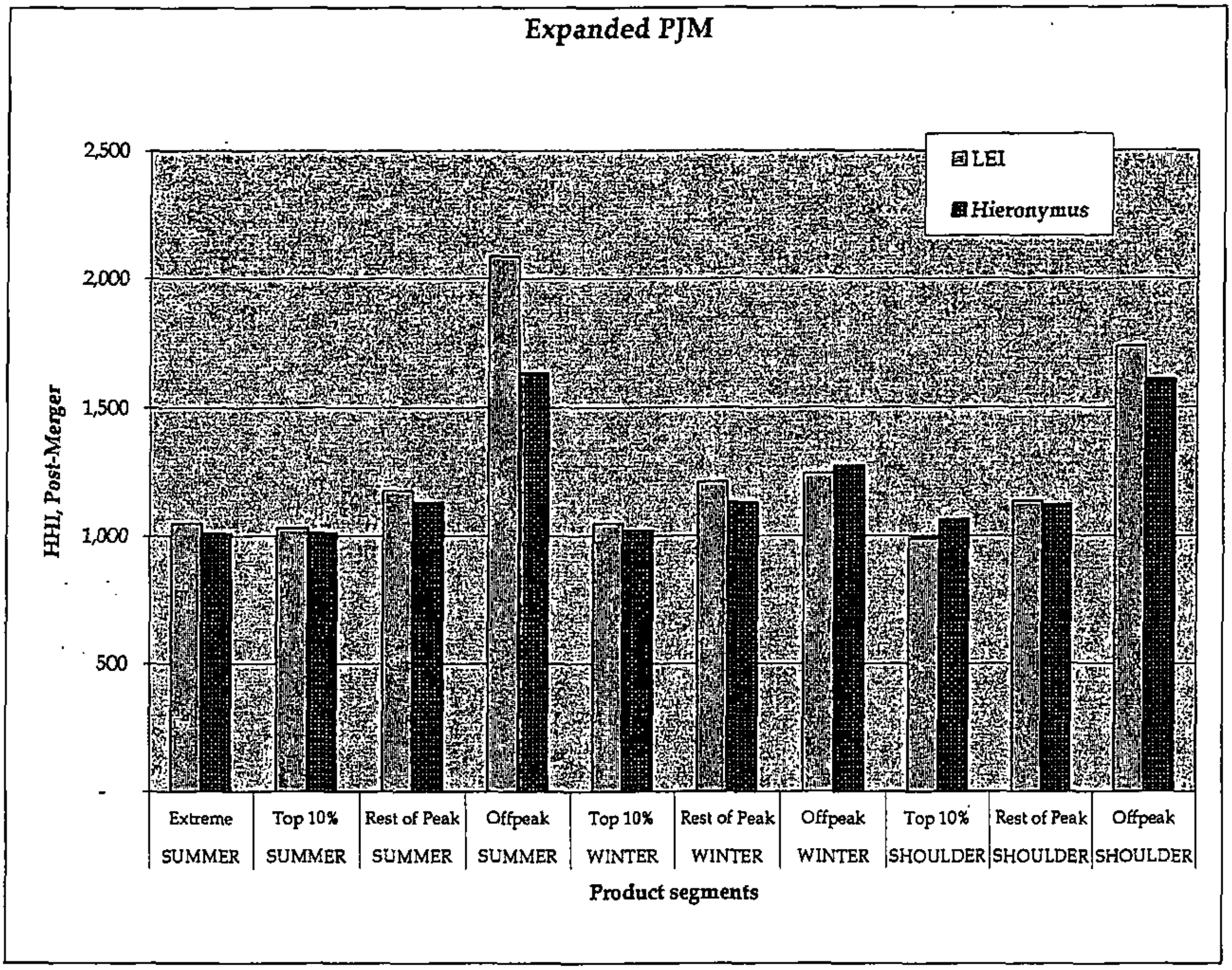
| Pre 2004 PJM | | | PRE MERGER | | | | | | POST MERGER | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Season | Period | Destination Market Price | Exelon MW | Exelon Market Share | PSEG MW | PSEG Market Share | Market Size | HHI | Merged Entity MW | Merged Entity Market Share | HHI | HHI Change | Status of screen failure? |
| SUMMER | Extreme | $113 | 9,661 | 13.49% | 10,825 | 15.12% | 71,613 | 875 | 20,486 | 28.61% | 1,283 | 408 | Fail |
| SUMMER | Top 10% | $84 | 8,908 | 13.73% | 8,264 | 12.74% | 64,884 | 853 | 17,172 | 26.47% | 1,203 | 350 | Fail |
| SUMMER | Rest of Peak | $65 | 8,039 | 14.79% | 7,651 | 14.07% | 54,368 | 938 | 15,690 | 28.86% | 1,354 | 416 | Fail |
| SUMMER | Offpeak | $37 | 7,228 | 31.86% | 3,192 | 14.07% | 22,685 | 1,494 | 10,420 | 45.93% | 2,390 | 895 | Fail |
| WINTER | Top 10% | $120 | 9,908 | 14.16% | 9,636 | 13.77% | 69,968 | 858 | 19,544 | 27.93% | 1,248 | 390 | Fail |
| WINTER | Rest of Peak | $76 | 8,365 | 16.51% | 6,375 | 12.58% | 50,678 | 1,017 | 14,740 | 29.09% | 1,433 | 415 | Fail |
| WINTER | Offpeak | $55 | 7,795 | 16.83% | 4,946 | 10.68% | 46,310 | 1,001 | 12,741 | 27.51% | 1,361 | 360 | Fail |
| SHOULDER | Top 10% | $83 | 8,033 | 14.46% | 6,678 | 12.02% | 55,538 | 832 | 14,711 | 26.49% | 1,180 | 348 | Fail |
| SHOULDER | Rest of Peak | $65 | 7,010 | 15.28% | 6,112 | 13.32% | 45,873 | 904 | 13,122 | 28.61% | 1,311 | 407 | Fail |
| SHOULDER | Offpeak | $42 | 6,358 | 30.67% | 2,728 | 13.16% | 20,731 | 1,392 | 9,085 | 43.83% | 2,199 | 807 | Fail |

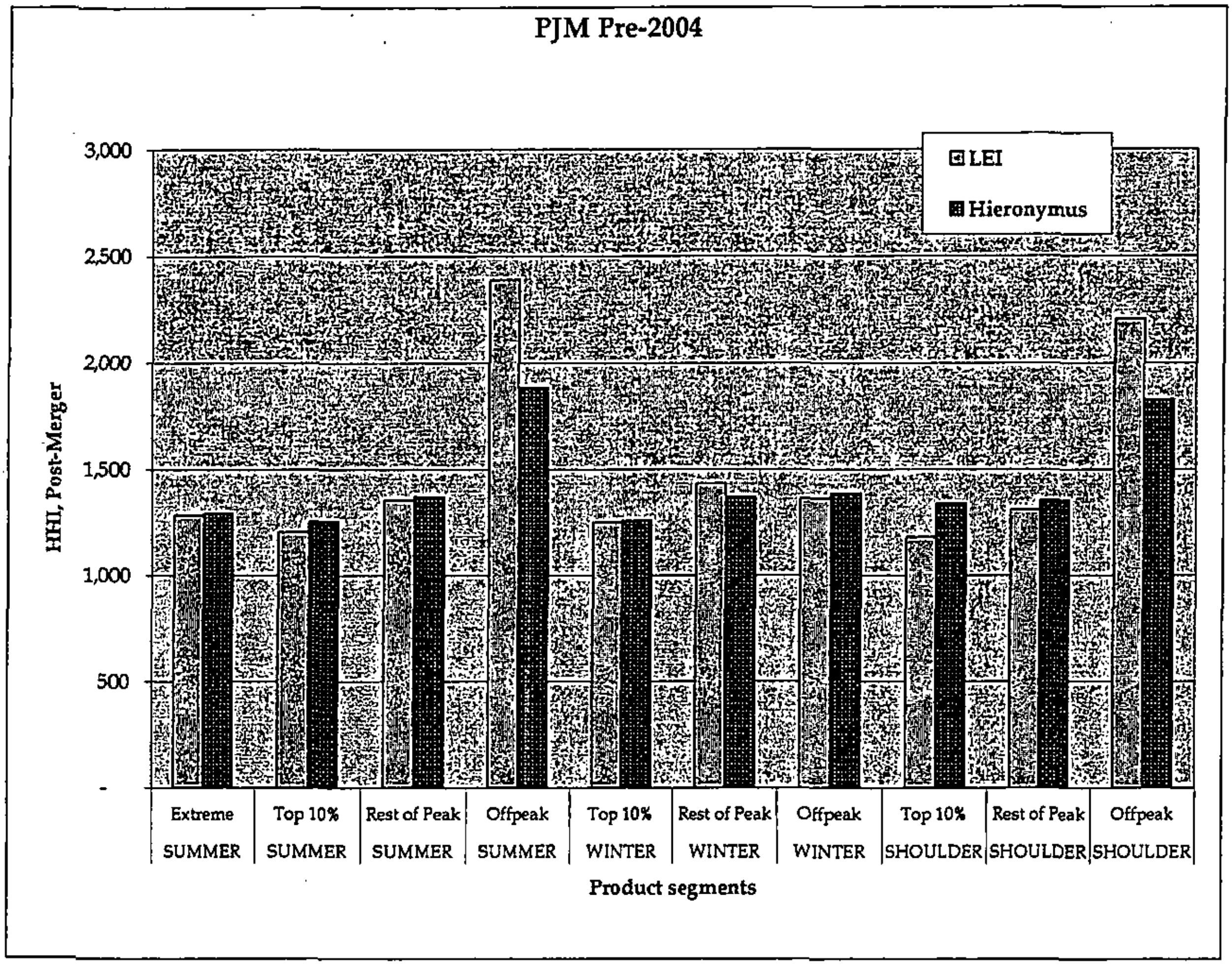
| PJM East | | | PRE MERGER | | | | | | POST MERGER | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Season | Period | Destination Market Price | Exelon MW | Exelon Market Share | PSEG MW | PSEG Market Share | Market Size | HHI | Merged Entity MW | Merged Entity Market Share | HHI | HHI Change | Status of screen failure? |
| SUMMER | Extreme | $125 | 6,094 | 17.42% | 9,450 | 27.02% | 34,980 | 1,326 | 15,544 | 44.44% | 2,267 | 941 | Fail |
| SUMMER | Top 10% | $87 | 5,379 | 17.20% | 7,438 | 23.78% | 31,276 | 1,177 | 12,817 | 40.98% | 1,995 | 818 | Fail |
| SUMMER | Rest of Peak | $69 | 5,143 | 20.83% | 6,141 | 24.87% | 24,695 | 921 | 11,284 | 45.69% | 1,327 | 406 | Fail |
| SUMMER | Offpeak | $41 | 5,412 | 34.03% | 2,710 | 17.04% | 15,906 | 1,658 | 8,122 | 51.06% | 2,818 | 1,159 | Fail |
| WINTER | Top 10% | $123 | 6,388 | 18.67% | 8,660 | 25.31% | 34,218 | 866 | 15,048 | 43.98% | 1,273 | 406 | Fail |
| WINTER | Rest of Peak | $80 | 5,535 | 25.08% | 4,877 | 22.10% | 22,067 | 1,353 | 10,411 | 47.18% | 2,461 | 1,109 | Fail |
| WINTER | Offpeak | $63 | 5,122 | 25.33% | 3,559 | 17.60% | 20,222 | 985 | 8,682 | 42.93% | 1,328 | 343 | Fail |
| SHOULDER | Top 10% | $86 | 4,896 | 17.80% | 5,926 | 21.55% | 27,497 | 835 | 10,822 | 39.36% | 1,196 | 362 | Fail |
| SHOULDER | Rest of Peak | $68 | 4,654 | 21.60% | 4,940 | 22.93% | 21,544 | 1,225 | 9,594 | 44.53% | 2,215 | 991 | Fail |
| SHOULDER | Offpeak | $45 | 4,163 | 28.55% | 2,049 | 14.05% | 14,583 | 1,178 | 6,212 | 42.60% | 1,651 | 473 | Fail |

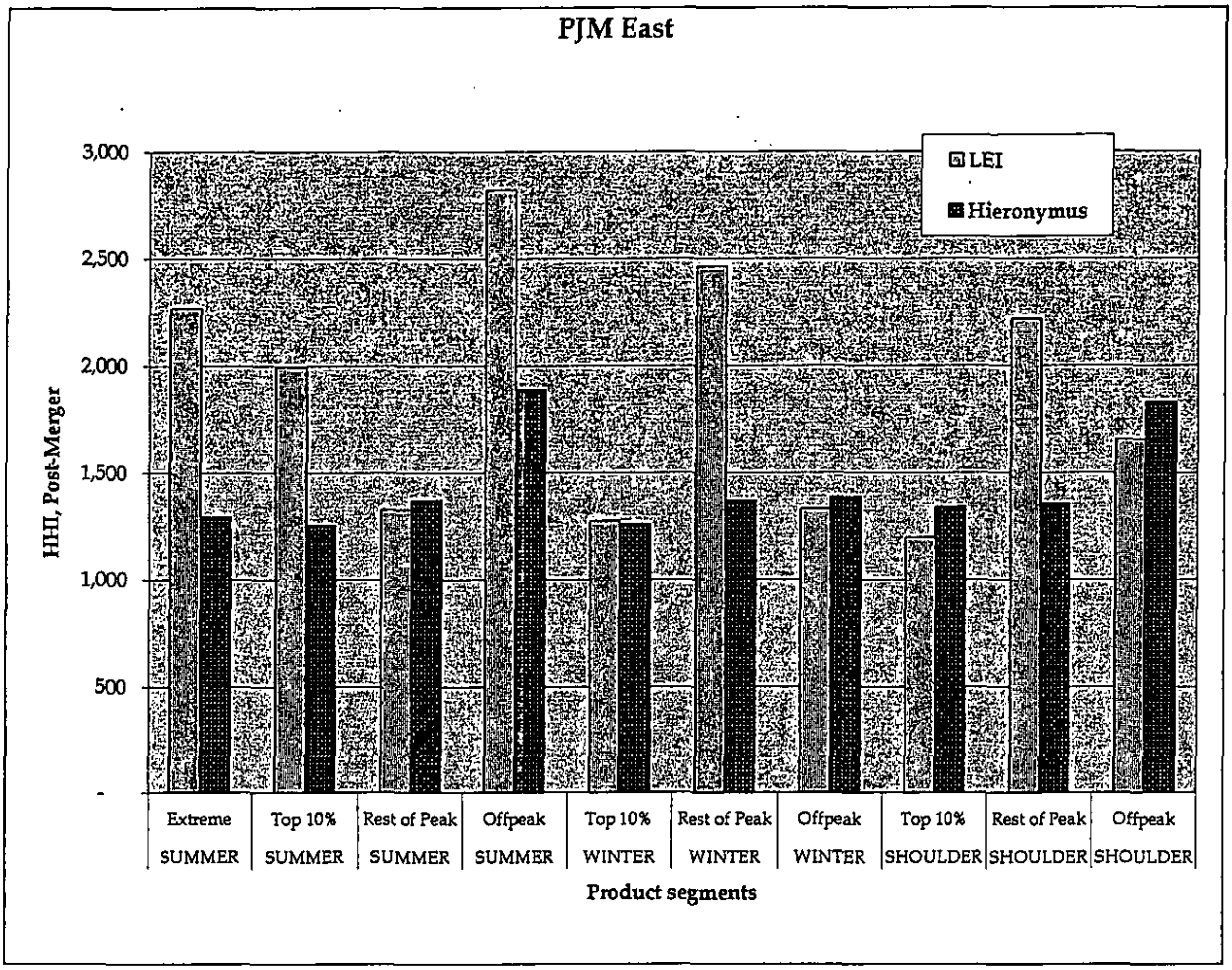
## Exhibit 12: LEI's Post-Merger HHIs for Economic Capacity (post-merger)



## Exhibit 13: Comparing Economic Capacity HHIs (post-merger)




PJM Pre-2004
LEI
Hieronymus
3,000
2,500
2,000
1,500
1,000
500
-
HHI, Post-Merger
Extreme SUMMER
Top 10% SUMMER
Rest of Peak SUMMER
Offpeak SUMMER
Top 10% WINTER
Rest of Peak WINTER
Offpeak WINTER
Top 10% SHOULDER
Rest of Peak SHOULDER
Offpeak SHOULDER
Product segments


PJM East
LEI
Hieronymus
3,000
2,500
2,000
1,500
1,000
500
-
HHI, Post-Merger
Extreme SUMMER
Top 10% SUMMER
Rest of Peak SUMMER
Offpeak SUMMER
Top 10% WINTER
Rest of Peak WINTER
Offpeak WINTER
Top 10% SHOULDER
Rest of Peak SHOULDER
Offpeak SHOULDER
Product segments

# Exhibit 14: LEI's Economic Capacity HHIs with Applicants' proposed mitigation (post-mitigation)

| PJM Expanded | | | PRE MERGER | | | | | | POST MERGER WTH MITIGATION | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Season | Period | Destination Market Price | Exelon MW | Exelon Market Share | PSEG MW | PSEG Market Share | Market Size | HHI | EEG MW | EEG Market Share | HHI | HHI Change | Is mitigation enough? |
| SUMMER | Extreme | $113 | 23,113 | 14.84% | 12,557 | 8.06% | 155,717 | 809 | 30,170 | 19.38% | 896 | 87 | OK |
| SUMMER | Top 10% | $84 | 22,363 | 15.25% | 9,997 | 6.82% | 146,625 | 823 | 26,860 | 18.32% | 905 | 82 | OK |
| SUMMER | Rest of Peak | $65 | 18,683 | 15.49% | 9,368 | 7.76% | 120,650 | 936 | 22,551 | 18.69% | 1,064 | 128 | Need More |
| SUMMER | Offpeak | $37 | 15,319 | 34.76% | 3,192 | 7.24% | 44,070 | 1,584 | 13,011 | 29.52% | 1,663 | 78 | OK |
| WINTER | Top 10% | $120 | 23,634 | 15.25% | 11,368 | 7.33% | 154,996 | 824 | 29,502 | 19.03% | 915 | 91 | OK |
| WINTER | Rest of Peak | $76 | 19,019 | 16.12% | 8,093 | 6.86% | 118,003 | 990 | 21,612 | 18.31% | 1,087 | 97 | OK |
| WINTER | Offpeak | $55 | 18,361 | 17.43% | 4,946 | 4.70% | 105,316 | 1,080 | 17,807 | 16.91% | 1,142 | 62 | OK |
| SHOULDER | Top 10% | $83 | 19,274 | 15.33% | 8,098 | 6.44% | 125,707 | 792 | 21,872 | 17.40% | 870 | 79 | OK |
| SHOULDER | Rest of Peak | $65 | 15,729 | 15.63% | 7,522 | 7.48% | 100,607 | 902 | 17,751 | 17.64% | 1,027 | 126 | Need More |
| SHOULDER | Offpeak | $42 | 13,530 | 31.42% | 2,728 | 6.34% | 43,059 | 1,342 | 10,757 | 24.98% | 1,419 | 77 | OK |

| Pre 2004 PJM | | | PRE MERGER | | | | | | POST MERGER WTH MITIGATION | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Season | Period | Destination Market Price | Exelon MW | Exelon Market Share | PSEG MW | PSEG Market Share | Market Size | HHI | EEG MW | EEG Market Share | HHI | HHI Change | |
| SUMMER | Extreme | $113 | 9,661 | 13.49% | 10,825 | 15.12% | 71,613 | 875 | 14,986 | 20.93% | 896 | 21 | OK |
| SUMMER | Top 10% | $84 | 8,908 | 13.73% | 8,264 | 12.74% | 64,884 | 853 | 11,672 | 17.99% | 884 | 31 | OK |
| SUMMER | Rest of Peak | $65 | 8,039 | 14.79% | 7,651 | 14.07% | 54,368 | 938 | 10,190 | 18.74% | 1,059 | 120 | Need More |
| SUMMER | Offpeak | $37 | 7,228 | 31.86% | 3,192 | 14.07% | 22,685 | 1,494 | 4,920 | 21.69% | 1,535 | 40 | OK |
| WINTER | Top 10% | $120 | 9,908 | 14.16% | 9,636 | 13.77% | 69,968 | 858 | 14,044 | 20.07% | 905 | 48 | OK |
| WINTER | Rest of Peak | $76 | 8,365 | 16.51% | 6,375 | 12.58% | 50,678 | 1,017 | 9,240 | 18.23% | 1,088 | 70 | OK |
| WINTER | Offpeak | $55 | 7,795 | 16.83% | 4,946 | 10.68% | 46,310 | 1,001 | 7,241 | 15.64% | 1,087 | 85 | OK |
| SHOULDER | Top 10% | $83 | 8,033 | 14.46% | 6,678 | 12.02% | 55,538 | 832 | 9,211 | 16.58% | 873 | 41 | OK |
| SHOULDER | Rest of Peak | $65 | 7,010 | 15.28% | 6,112 | 13.32% | 45,873 | 904 | 7,622 | 16.62% | 1,030 | 126 | Need More |
| SHOULDER | Offpeak | $42 | 6,358 | 30.67% | 2,728 | 13.16% | 20,731 | 1,392 | 3,585 | 17.30% | 1,463 | 71 | OK |

| PJM East | | | PRE MERGER | | | | | | POST MERGER WTH MITIGATION | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Season | Period | Destination Market Price | Exelon MW | Exelon Market Share | PSEG MW | PSEG Market Share | Market Size | HHI | EEG MW | EEG Market Share | HHI | HHI Change | |
| SUMMER | Extreme | $125 | 6,094 | 17.42% | 9,450 | 27.02% | 34,980 | 1,326 | 10,044 | 28.71% | 1,222 | (103) | OK |
| SUMMER | Top 10% | $87 | 5,379 | 17.20% | 7,438 | 23.78% | 31,276 | 1,177 | 7,317 | 23.39% | 1,120 | (57) | OK |
| SUMMER | Rest of Peak | $69 | 5,143 | 20.83% | 6,141 | 24.87% | 24,695 | 921 | 5,784 | 23.42% | 1,039 | 117 | Need More |
| SUMMER | Offpeak | $41 | 5,412 | 34.03% | 2,710 | 17.04% | 15,906 | 1,658 | 2,622 | 16.49% | 1,596 | (62) | OK |
| WINTER | Top 10% | $129 | 6,388 | 18.67% | 8,660 | 25.31% | 34,218 | 866 | 9,548 | 27.90% | 925 | 58 | OK |
| WINTER | Rest of Peak | $80 | 5,535 | 25.08% | 4,877 | 22.10% | 22,067 | 1,353 | 4,911 | 22.26% | 1,415 | 62 | OK |
| WINTER | Offpeak | $63 | 5,122 | 25.33% | 3,559 | 17.60% | 20,222 | 985 | 3,182 | 15.73% | 1,066 | 81 | OK |
| SHOULDER | Top 10% | $86 | 4,896 | 17.80% | 5,926 | 21.55% | 27,497 | 839 | 5,322 | 19.36% | 887 | 52 | OK |
| SHOULDER | Rest of Peak | $68 | 4,654 | 21.60% | 4,940 | 22.93% | 21,544 | 1,225 | 4,094 | 19.00% | 1,411 | 187 | Need More |
| SHOULDER | Offpeak | $45 | 4,163 | 28.55% | 2,049 | 14.05% | 14,583 | 1,178 | 712 | 4.88% | 1,212 | 34 | OK |



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717 Atlantic Ave, Unit 1A
Boston, MA 02111
www.londoneconomics.com

**Exhibit 15: LEI's proposed additional mitigation (MW)**

| *Baseline Scenario* | PJM East | | | PJM Pre 2004 | | | PJM Expanded | | |
|---|---|---|---|---|---|---|---|---|---|
| | Summer | Winter | Shoulder | Summer | Winter | Shoulder | Summer | Winter | Shoulder |
| Baseload | - | - | - | - | - | - | - | - | - |
| Mid Merit | 390 | 411 | 390 | 370 | 390 | 370 | 890 | 937 | 890 |
| Peaking | - | - | - | - | - | - | - | - | - |
| TOTAL | 390 | 411 | 390 | 370 | 390 | 370 | 890 | 937 | 890 |

| Baseline -25% Scenario | PJM East | | | PJM Pre 2004 | | | PJM Expanded | | |
|---|---|---|---|---|---|---|---|---|---|
| | Summer | Winter | Shoulder | Summer | Winter | Shoulder | Summer | Winter | Shoulder |
| Baseload | - | - | - | - | - | - | - | - | - |
| Mid Merit | - | - | - | - | - | - | - | - | - |
| Peaking | - | - | - | - | - | - | - | - | - |
| TOTAL | - | - | - | - | - | - | - | - | - |

| Baseline +25% Scenario | PJM East | | | PJM Pre 2004 | | | PJM Expanded | | |
|---|---|---|---|---|---|---|---|---|---|
| | Summer | Winter | Shoulder | Summer | Winter | Shoulder | Summer | Winter | Shoulder |
| Baseload | 410 | 426 | 410 | 50 | 52 | 50 | - | - | - |
| Mid Merit | 550 | 579 | 550 | - | - | - | - | - | - |
| Peaking | - | - | - | - | - | - | - | - | - |
| TOTAL | 960 | 1,006 | 960 | 50 | 52 | 50 | - | - | - |

# Exhibit 16: Summary of Baseline -25% sensitivity case for LEI's Economic Capacity HHIs (post-merger)

| PJM Expanded | | | PRE MERGER | | | | | | POST MERGER | | | | | POST MERGER WTH MITIGATION | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Season | Period | Destination Market Price | Exelon MW | Exelon Market Share | PSEG MW | PSEG Market Share | Market Size | HHI | Merged Entity MW | Merged Entity Market Share | HHI | HHI Change | Status of screen failure? | EEG MW | EEG Market Share | HHI | HHI Change | Is mitigation enough? |
| SUMMER | Extreme | $ 125 | 23,113 | 14.78% | 12,728 | 8.14% | 156,348 | 807 | 35,841 | 22.92% | 1,048 | 241 | Fail | 30,224 | 19.33% | 896 | 89 | OK |
| SUMMER | Top 10% | $ 87 | 22,363 | 15.12% | 10,702 | 7.23% | 147,918 | 818 | 33,065 | 22.35% | 1,037 | 219 | Fail | 28,565 | 19.31% | 910 | 92 | OK |
| SUMMER | Rest of Peak | $ 69 | 18,683 | 15.39% | 9,367 | 7.72% | 121,413 | 927 | 28,050 | 23.10% | 1,164 | 237 | Fail | 24,961 | 20.56% | 1,053 | 126 | Need More |
| SUMMER | Offpeak | $ 41 | 15,312 | 32.01% | 3,192 | 6.67% | 47,836 | 1,404 | 18,504 | 38.68% | 1,832 | 427 | Fail | 16,119 | 33.70% | 1,471 | 66 | OK |
| WINTER | Top 10% | $ 123 | 23,634 | 15.18% | 11,938 | 7.67% | 155,665 | 823 | 35,572 | 22.85% | 1,056 | 233 | Fail | 30,669 | 19.70% | 922 | 99 | OK |
| WINTER | Rest of Peak | $ 80 | 22,131 | 17.79% | 8,089 | 6.50% | 124,374 | 995 | 30,221 | 24.30% | 1,226 | 231 | Fail | 26,823 | 21.57% | 1,101 | 106 | Need More |
| WINTER | Offpeak | $ 63 | 18,358 | 16.92% | 4,946 | 4.56% | 108,484 | 1,053 | 23,304 | 21.48% | 1,207 | 154 | Fail | 20,736 | 19.11% | 1,111 | 58 | OK |
| SHOULDER | Top 10% | $ 86 | 19,274 | 15.23% | 8,549 | 6.76% | 126,535 | 787 | 27,823 | 21.99% | 993 | 206 | Pass | 24,143 | 19.08% | 873 | 86 | OK |
| SHOULDER | Rest of Peak | $ 68 | 15,729 | 15.62% | 7,522 | 7.47% | 100,676 | 901 | 23,251 | 23.10% | 1,134 | 233 | Fail | 20,761 | 20.62% | 1,026 | 125 | Need More |
| SHOULDER | Offpeak | $ 45 | 14,274 | 22.16% | 2,728 | 4.24% | 64,409 | 1,199 | 17,001 | 26.40% | 1,387 | 188 | Fail | 15,051 | 23.37% | 1,236 | 37 | OK |

| Pre 2004 PJM | | | PRE MERGER | | | | | | POST MERGER | | | | | POST MERGER WTH MITIGATION | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Season | Period | Destination Market Price | Exelon MW | Exelon Market Share | PSEG MW | PSEG Market Share | Market Size | HHI | Merged Entity MW | Merged Entity Market Share | HHI | HHI Change | Status of screen failure? | EEG MW | EEG Market Share | HHI | HHI Change | |
| SUMMER | Extreme | $ 125 | 9,660 | 13.40% | 10,996 | 15.26% | 72,067 | 877 | 20,656 | 28.66% | 1,286 | 409 | Fail | 15,039 | 20.87% | 900 | 23 | OK |
| SUMMER | Top 10% | $ 87 | 8,908 | 13.47% | 8,969 | 13.56% | 66,133 | 857 | 17,877 | 27.03% | 1,222 | 365 | Fail | 13,377 | 20.23% | 901 | 44 | OK |
| SUMMER | Rest of Peak | $ 69 | 8,038 | 14.60% | 7,651 | 13.89% | 55,064 | 921 | 15,689 | 28.49% | 1,327 | 406 | Fail | 17,600 | 22.88% | 1,039 | 117 | Need More |
| SUMMER | Offpeak | $ 41 | 7,008 | 30.87% | 3,192 | 14.06% | 22,700 | 1,431 | 10,199 | 44.93% | 2,298 | 867 | Fail | 7,815 | 34.43% | 1,464 | 34 | OK |
| WINTER | Top 10% | $ 123 | 9,907 | 14.04% | 10,206 | 14.47% | 70,549 | 866 | 20,113 | 28.51% | 1,273 | 406 | Fail | 15,210 | 21.56% | 925 | 58 | OK |
| WINTER | Rest of Peak | $ 80 | 8,489 | 16.75% | 6,365 | 12.56% | 50,678 | 1,024 | 14,854 | 29.31% | 1,445 | 421 | Fail | 11,456 | 27.61% | 1,097 | 73 | OK |
| WINTER | Offpeak | $ 63 | 7,768 | 16.41% | 4,946 | 10.45% | 47,335 | 985 | 12,714 | 26.86% | 1,328 | 343 | Fail | 10,146 | 21.43% | 1,066 | 81 | OK |
| SHOULDER | Top 10% | $ 86 | 8,032 | 14.27% | 7,130 | 12.67% | 56,273 | 835 | 15,162 | 26.94% | 1,196 | 362 | Fail | 11,482 | 20.40% | 887 | 52 | OK |
| SHOULDER | Rest of Peak | $ 68 | 7,010 | 15.26% | 6,112 | 13.31% | 45,936 | 902 | 13,122 | 28.57% | 1,308 | 406 | Fail | 10,632 | 23.15% | 1,028 | 126 | Need More |
| SHOULDER | Offpeak | $ 45 | 5,886 | 22.59% | 2,728 | 10.47% | 26,056 | 1,178 | 8,614 | 33.06% | 1,651 | 473 | Fail | 6,664 | 25.57% | 1,212 | 34 | OK |

| PJM East | | | PRE MERGER | | | | | | POST MERGER | | | | | POST MERGER WTH MITIGATION | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Season | Period | Destination Market Price | Exelon MW | Exelon Market Share | PSEG MW | PSEG Market Share | Market Size | HHI | Merged Entity MW | Merged Entity Market Share | HHI | HHI Change | Status of screen failure? | EEG MW | EEG Market Share | HHI | HHI Change | |
| SUMMER | Extreme | $ 141 | 5,407 | 16.65% | 8,015 | 24.68% | 32,472 | 1,209 | 13,422 | 41.33% | 2,031 | 822 | Fail | 8,545 | 26.32% | 1,015 | (194) | OK |
| SUMMER | Top 10% | $ 105 | 5,234 | 20.94% | 6,277 | 25.11% | 25,001 | 1,285 | 11,511 | 46.04% | 2,337 | 1,051 | Fail | 7,565 | 30.26% | 1,132 | (153) | OK |
| SUMMER | Rest of Peak | $ 81 | 5,092 | 25.06% | 3,889 | 19.14% | 20,319 | 924 | 8,980 | 44.20% | 1,310 | 387 | Fail | 6,262 | 30.82% | 980 | 57 | OK |
| SUMMER | Offpeak | $ 46 | 5,591 | 35.29% | 2,728 | 17.21% | 15,845 | 1,748 | 8,319 | 52.50% | 2,963 | 1,215 | Fail | 6,118 | 38.61% | 1,697 | (51) | OK |
| WINTER | Top 10% | $ 150 | 5,563 | 21.14% | 6,417 | 24.38% | 26,321 | 926 | 11,980 | 45.52% | 1,343 | 417 | Fail | 7,919 | 30.08% | 929 | 3 | OK |
| WINTER | Rest of Peak | $ 95 | 5,515 | 26.66% | 3,580 | 17.31% | 20,686 | 1,278 | 9,095 | 43.97% | 2,201 | 923 | Fail | 6,262 | 30.27% | 1,184 | (94) | OK |
| WINTER | Offpeak | $ 69 | 5,072 | 27.43% | 3,597 | 19.45% | 18,491 | 1,017 | 8,669 | 46.88% | 1,439 | 422 | Fail | 6,379 | 34.50% | 1,116 | 99 | OK |
| SHOULDER | Top 10% | $ 104 | 4,788 | 21.57% | 5,048 | 22.74% | 22,196 | 919 | 9,836 | 44.31% | 1,330 | 411 | Fail | 6,603 | 29.75% | 948 | 29 | OK |
| SHOULDER | Rest of Peak | $ 81 | 4,742 | 26.07% | 2,933 | 16.12% | 18,190 | 1,224 | 7,674 | 42.19% | 2,064 | 840 | Fail | 5,478 | 30.12% | 1,191 | (32) | OK |
| SHOULDER | Offpeak | $ 53 | 4,947 | 34.86% | 2,102 | 14.81% | 14,191 | 1,443 | 7,049 | 49.67% | 2,235 | 791 | Fail | 5,249 | 36.99% | 1,455 | 12 | OK |

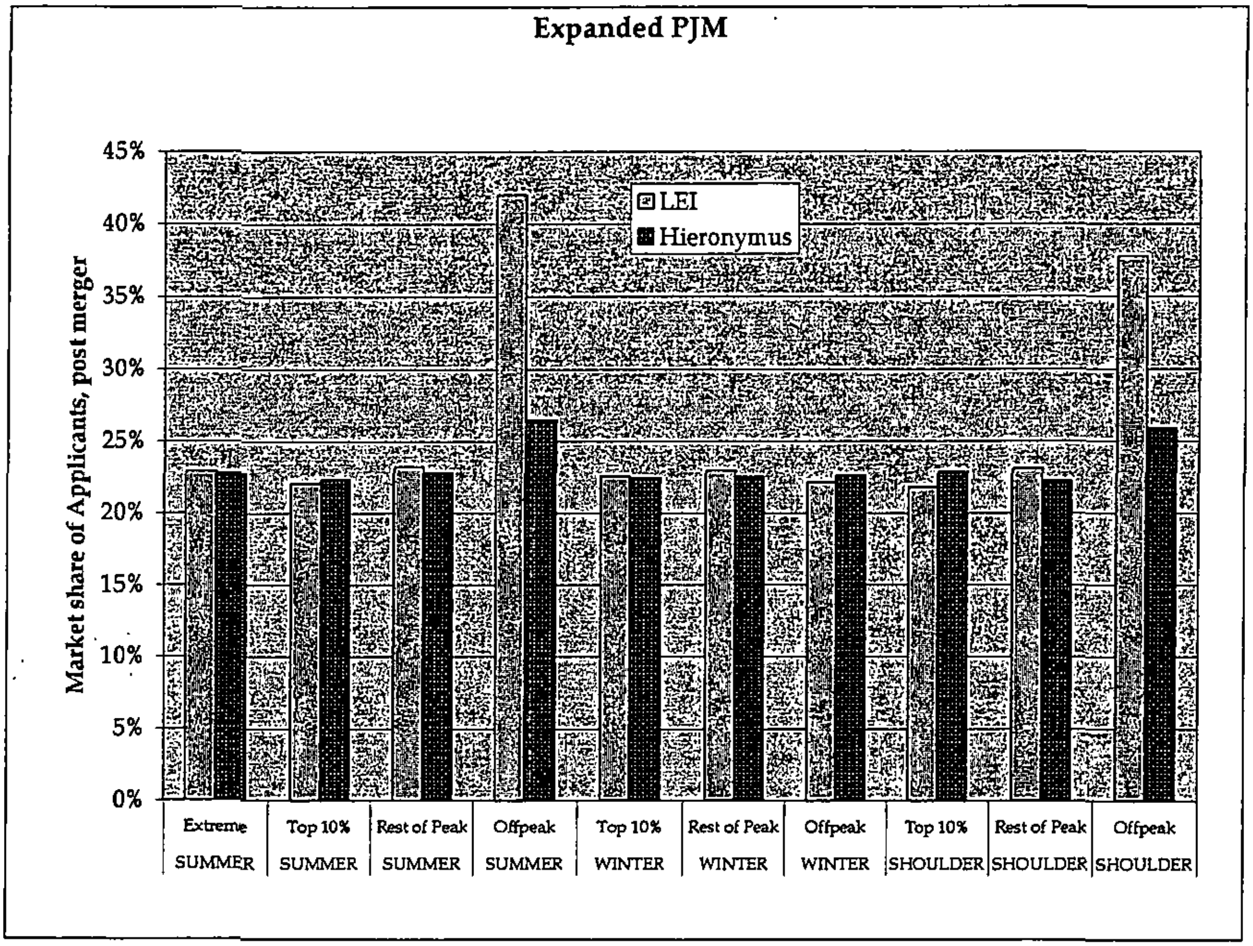
## Exhibit 17: Summary of Baseline +25% sensitivity case for LEI's Economic Capacity HHIs (post-merger)

| PJM Expanded | | | PRE MERGER | | | | | | POST MERGER | | | | Status of screen failure? | POST MERGER WTH MITIGATION | | | | Is mitigation enough? |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Season | Period | Destination Market Price | Exelon MW | Exelon Market Share | PSEG MW | PSEG Market Share | Market Size | HHI | Merged Entity MW | Merged Entity Market Share | HHI | HHI Change | | EEG MW | EEG Market Share | HHI | HHI Change | |
| SUMMER | Extreme | $ 141 | 23,358 | 14.75% | 12,966 | 8.19% | 158,338 | 798 | 36,924 | 22.94% | 1,040 | 242 | Fail | 30,707 | 19.39% | 890 | 91 | OK |
| SUMMER | Top 10% | $ 105 | 23,124 | 15.03% | 11,576 | 7.52% | 153,883 | 813 | 34,700 | 22.55% | 1,040 | 226 | Fail | 30,200 | 19.63% | 916 | 103 | OK |
| SUMMER | Rest of Peak | $ 81 | 21,713 | 15.13% | 9,777 | 6.81% | 143,470 | 822 | 31,491 | 21.95% | 1,029 | 206 | Fail | 28,401 | 19.80% | 939 | 116 | OK |
| SUMMER | Offpeak | $ 46 | 17,228 | 22.65% | 3,556 | 4.68% | 76,072 | 1,329 | 20,784 | 27.32% | 1,541 | 212 | Fail | 18,399 | 24.19% | 1,379 | 50 | OK |
| WINTER | Top 10% | $ 150 | 24,018 | 15.02% | 12,752 | 7.97% | 159,916 | 808 | 36,770 | 22.99% | 1,047 | 240 | Fail | 31,867 | 19.93% | 916 | 108 | OK |
| WINTER | Rest of Peak | $ 95 | 22,137 | 16.00% | 9,153 | 6.61% | 138,374 | 884 | 31,289 | 22.61% | 1,095 | 212 | Fail | 27,892 | 20.16% | 990 | 107 | OK |
| WINTER | Offpeak | $ 69 | 18,366 | 16.47% | 4,946 | 4.43% | 111,546 | 1,012 | 23,312 | 20.90% | 1,158 | 146 | Fail | 20,744 | 18.60% | 1,067 | 55 | OK |
| SHOULDER | Top 10% | $ 104 | 19,828 | 15.02% | 9,325 | 7.06% | 132,019 | 787 | 29,153 | 22.08% | 995 | 212 | Pass | 25,473 | 19.30% | 879 | 97 | OK |
| SHOULDER | Rest of Peak | $ 81 | 18,534 | 15.13% | 7,826 | 6.39% | 122,491 | 785 | 26,360 | 21.52% | 978 | 193 | Pass | 23,870 | 19.49% | 895 | 110 | OK |
| SHOULDER | Offpeak | $ 53 | 15,141 | 17.91% | 3,945 | 4.67% | 84,546 | 1,059 | 19,086 | 22.58% | 1,226 | 167 | Fail | 17,136 | 20.27% | 1,128 | 68 | OK |

| Pre 2004 PJM | | | PRE MERGER | | | | | | POST MERGER | | | | Status of screen failure? | POST MERGER WTH MITIGATION | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Season | Period | Destination Market Price | Exelon MW | Exelon Market Share | PSEG MW | PSEG Market Share | Market Size | HHI | Merged Entity MW | Merged Entity Market Share | HHI | HHI Change | | EEG MW | EEG Market Share | HHI | HHI Change | |
| SUMMER | Extreme | $ 141 | 9,908 | 13.45% | 11,234 | 15.25% | 73,675 | 870 | 21,141 | 28.70% | 1,280 | 410 | Fail | 15,525 | 21.07% | 900 | 31 | OK |
| SUMMER | Top 10% | $ 105 | 9,633 | 13.75% | 9,858 | 14.07% | 70,043 | 857 | 19,491 | 27.83% | 1,244 | 387 | Fail | 14,991 | 21.40% | 928 | 71 | OK |
| SUMMER | Rest of Peak | $ 81 | 8,252 | 13.16% | 8,063 | 12.86% | 62,723 | 841 | 16,315 | 26.01% | 1,179 | 338 | Fail | 13,226 | 21.09% | 947 | 106 | OK |
| SUMMER | Offpeak | $ 46 | 7,228 | 31.86% | 3,192 | 14.07% | 22,685 | 1,494 | 10,420 | 45.93% | 2,019 | 525 | Fail | 8,035 | 35.42% | 1,416 | (79) | OK |
| WINTER | Top 10% | $ 150 | 10,311 | 13.94% | 11,020 | 14.89% | 73,997 | 863 | 21,332 | 28.83% | 1,278 | 415 | Fail | 16,429 | 22.20% | 940 | 77 | OK |
| WINTER | Rest of Peak | $ 95 | 8,386 | 14.86% | 7,352 | 13.03% | 56,439 | 903 | 15,738 | 27.89% | 1,290 | 387 | Fail | 12,341 | 21.87% | 991 | 88 | OK |
| WINTER | Offpeak | $ 69 | 7,832 | 16.35% | 4,946 | 10.32% | 47,911 | 1,001 | 12,778 | 26.67% | 1,339 | 338 | Fail | 10,210 | 21.31% | 1,082 | 80 | OK |
| SHOULDER | Top 10% | $ 104 | 8,490 | 14.20% | 7,898 | 13.21% | 59,801 | 832 | 16,388 | 27.40% | 1,207 | 375 | Fail | 12,708 | 21.25% | 908 | 76 | OK |
| SHOULDER | Rest of Peak | $ 81 | 7,185 | 13.46% | 6,398 | 11.99% | 53,368 | 804 | 13,583 | 25.45% | 1,127 | 323 | Fail | 11,093 | 20.79% | 911 | 107 | OK |
| SHOULDER | Offpeak | $ 53 | 6,520 | 17.51% | 3,945 | 10.60% | 37,235 | 1,006 | 10,465 | 28.10% | 1,377 | 371 | Fail | 8,515 | 22.87% | 1,110 | 104 | Need More |

| PJM East | | | PRE MERGER | | | | | | POST MERGER | | | | Status of screen failure? | POST MERGER WTH MITIGATION | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Season | Period | Destination Market Price | Exelon MW | Exelon Market Share | PSEG MW | PSEG Market Share | Market Size | HHI | Merged Entity MW | Merged Entity Market Share | HHI | HHI Change | | EEG MW | EEG Market Share | HHI | HHI Change | |
| SUMMER | Extreme | $ 113 | 6,098 | 17.55% | 9,280 | 26.70% | 34,755 | 1,317 | 15,378 | 44.25% | 2,254 | 937 | Fail | 10,501 | 30.22% | 1,209 | (108) | OK |
| SUMMER | Top 10% | $ 84 | 5,380 | 17.89% | 6,733 | 22.39% | 30,073 | 1,126 | 12,113 | 40.28% | 1,927 | 801 | Fail | 8,166 | 27.15% | 1,042 | (84) | OK |
| SUMMER | Rest of Peak | $ 65 | 5,151 | 21.12% | 6,145 | 25.20% | 24,386 | 938 | 11,295 | 46.32% | 1,354 | 416 | Fail | 8,577 | 35.17% | 1,059 | 120 | Need More |
| SUMMER | Offpeak | $ 37 | 5,531 | 34.88% | 2,711 | 17.10% | 15,856 | 1,721 | 8,241 | 51.98% | 2,914 | 1,193 | Fail | 6,040 | 38.09% | 1,663 | (58) | OK |
| WINTER | Top 10% | $ 120 | 6,389 | 18.99% | 8,090 | 24.05% | 33,638 | 858 | 14,478 | 43.04% | 1,248 | 390 | Fail | 10,417 | 30.97% | 905 | 48 | OK |
| WINTER | Rest of Peak | $ 76 | 5,509 | 24.97% | 4,879 | 22.12% | 22,061 | 1,348 | 10,388 | 47.09% | 2,453 | 1,105 | Fail | 7,555 | 34.24% | 1,408 | 60 | OK |
| WINTER | Offpeak | $ 55 | 5,145 | 25.72% | 3,568 | 17.84% | 20,005 | 1,001 | 8,714 | 43.56% | 1,361 | 360 | Fail | 6,424 | 32.11% | 1,087 | 85 | OK |
| SHOULDER | Top 10% | $ 83 | 4,901 | 18.17% | 5,476 | 20.30% | 26,970 | 832 | 10,377 | 38.48% | 1,180 | 348 | Fail | 7,144 | 26.49% | 879 | 41 | OK |
| SHOULDER | Rest of Peak | $ 65 | 4,656 | 21.61% | 4,941 | 22.93% | 21,544 | 1,225 | 9,596 | 44.54% | 2,216 | 991 | Fail | 7,400 | 34.35% | 1,412 | 187 | Need More |
| SHOULDER | Offpeak | $ 42 | 4,849 | 33.87% | 2,218 | 15.49% | 14,316 | 1,392 | 7,067 | 49.36% | 2,199 | 807 | Fail | 5,267 | 36.79% | 1,463 | 71 | OK |

**Exhibit 18: Comparison of market shares estimated in the Delivered Price Test for Economic Capacity (post merger)**





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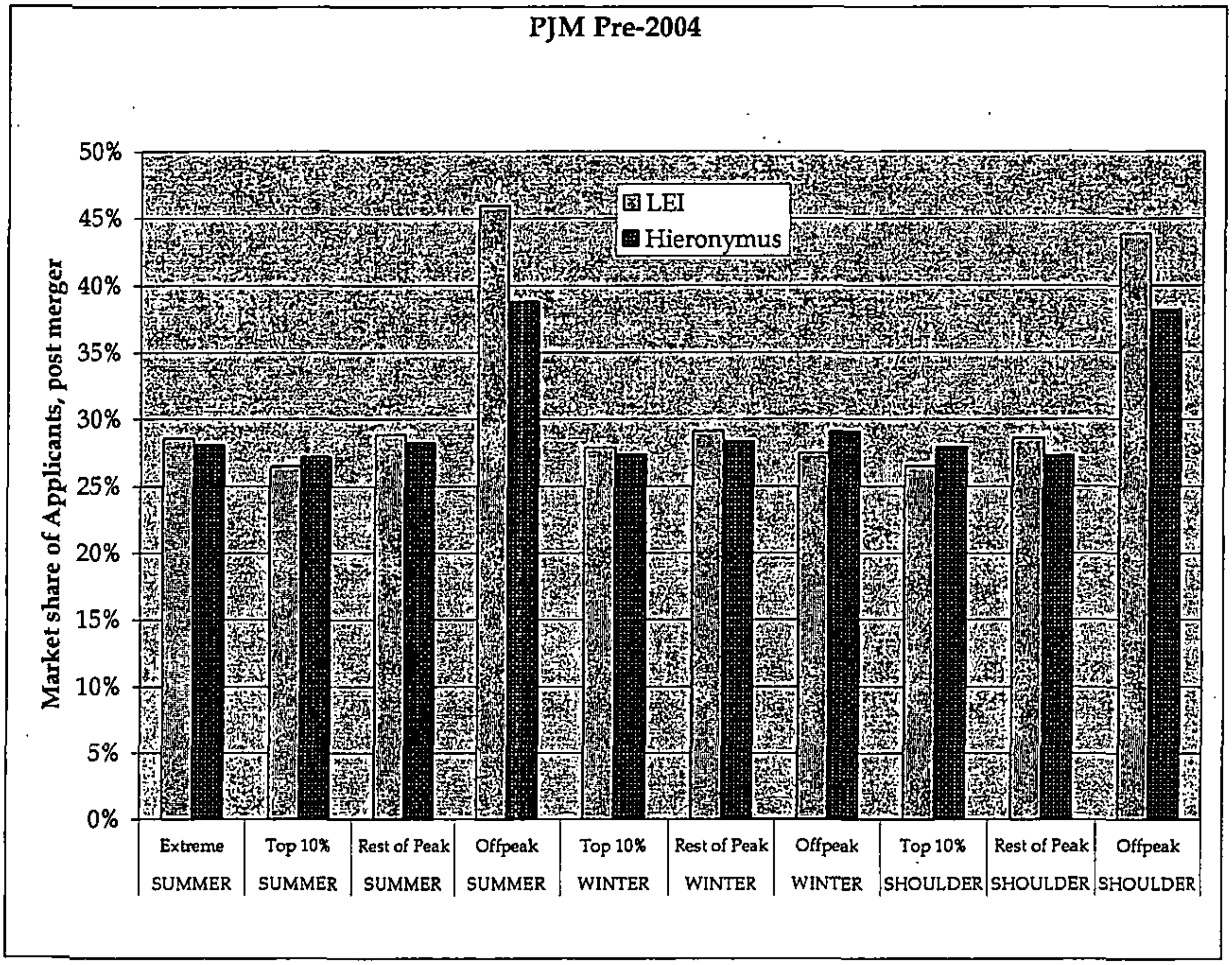
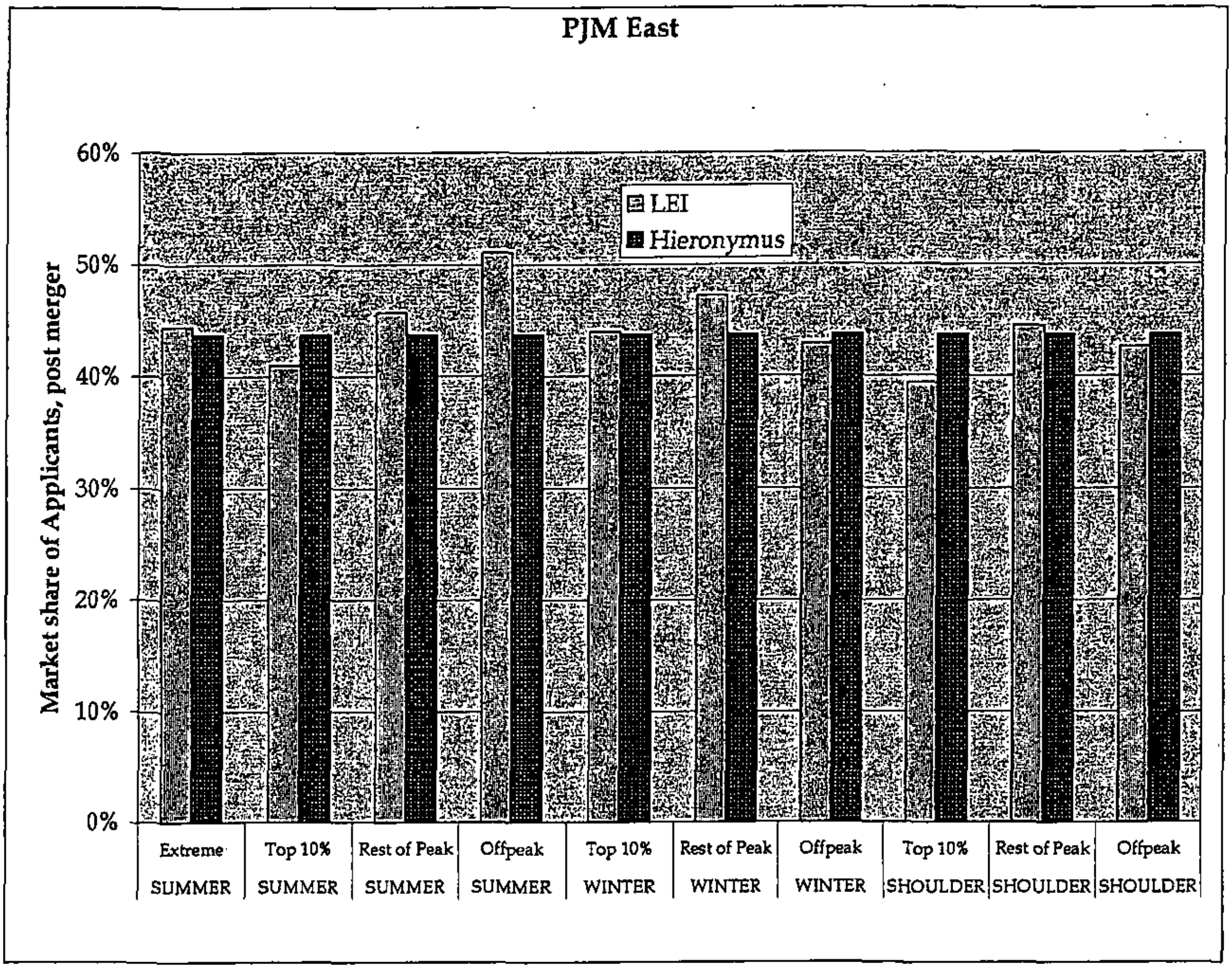

PJM Pre-2004
LEI
Hieronymus
Market share of Applicants, post merger
50%
45%
40%
35%
30%
25%
20%
15%
10%
5%
0%
Extreme SUMMER
Top 10% SUMMER
Rest of Peak SUMMER
Offpeak SUMMER
Top 10% WINTER
Rest of Peak WINTER
Offpeak WINTER
Top 10% SHOULDER
Rest of Peak SHOULDER
Offpeak SHOULDER



PJM East
LEI
Hieronymus
Market share of Applicants, post merger
60%
50%
40%
30%
20%
10%
0%
Extreme
SUMMER
Top 10%
SUMMER
Rest of Peak
SUMMER
Offpeak
SUMMER
Top 10%
WINTER
Rest of Peak
WINTER
Offpeak
WINTER
Top 10%
SHOULDER
Rest of Peak
SHOULDER
Offpeak
SHOULDER

## Exhibit 19: Summary results of the market share analysis per FERC's April 14th Order

| Pre-Mitigation | | Calculations | Winter | Spring | Summer | Fall |
|---|---|---|---|---|---|---|
| Applicant's Affiliated Uncommitted Supply | A | | 40,936 | 40,936 | 40,936 | 40,936 |
| Native Load | B2 | | 14,160 | 12,853 | 13,193 | 13,798 |
| Operating Reserves | B | | 1,155 | 1,155 | 1,155 | 1,155 |
| Planned Outages | C | | 1,303 | 447 | 357 | 513 |
| Hydro Derates | D | | 0 | 0 | 0 | 0 |
| **Applicant Uncommitted Capacity** | E | =A-B-B2-C-D | **24,318** | **26,481** | **26,231** | **25,470** |
| Local Generation in PJM Classic and PJM West | F | | 161,149 | 161,149 | 161,149 | 161,149 |
| Hydro Derates | G | | 0 | 0 | 0 | 0 |
| Other Native Load Commitments | H | | 79,608 | 73,747 | 75,147 | 74,713 |
| Operating Reserves (relative to Avg Daily Peak) | I | | 4,618 | 4,618 | 4,618 | 4,618 |
| Planned Outages | J | | 5,211 | 1,789 | 1,427 | 2,051 |
| Competing Imports from 'first-tier' markets | K | | 5,713 | 5,713 | 5,713 | 5,713 |
| **Total Uncommitted Supply** | L | =F-G-H-J+K | **77,425** | **86,708** | **85,670** | **85,480** |
| **Applicant's Affiliated Market Share** | M | =E/L | **31.4%** | **30.5%** | **30.6%** | **29.8%** |
| *Do Applicant and its affiliates pass the Market Share Test?* | N | =M<20% | no | no | no | no |

| Post-Mitigation | | Calculations | Winter | Spring | Summer | Fall |
|---|---|---|---|---|---|---|
| Applicant's Affiliated Uncommitted Supply | A | | 35,594 | 35,594 | 35,594 | 35,594 |
| Native Load | B2 | | 14,160 | 12,853 | 13,193 | 13,798 |
| Operating Reserves | B | | 997 | 997 | 997 | 997 |
| Planned Outages | C | | 1,125 | 386 | 308 | 443 |
| Hydro Derates | D | | 0 | 0 | 0 | 0 |
| **Applicant Uncommitted Capacity** | E | =A-B-B2-C-D | **19,311** | **21,357** | **21,095** | **20,355** |
| Local Generation in PJM Classic and PJM West | F | | 161,149 | 161,149 | 161,149 | 161,149 |
| Hydro Derates | G | | 0 | 0 | 0 | 0 |
| Other Native Load Commitments | H | | 79,608 | 73,747 | 75,147 | 74,713 |
| Operating Reserves (relative to Avg Daily Peak) | I | | 4,618 | 4,618 | 4,618 | 4,618 |
| Planned Outages | J | | 5,211 | 1,789 | 1,427 | 2,051 |
| Competing Imports from 'first-tier' markets | K | | 5,713 | 5,713 | 5,713 | 5,713 |
| **Total Uncommitted Supply** | L | =F-G-H-J+K | **77,425** | **86,708** | **85,670** | **85,480** |
| **Applicant's Affiliated Market Share** | M | =E/L | **24.9%** | **24.6%** | **24.6%** | **23.8%** |
| *Do Applicant and its affiliates pass the Market Share Test?* | N | =M<20% | no | no | no | no |

# Exhibit 20: HHI results from the Concentration Test of Spare Capacity

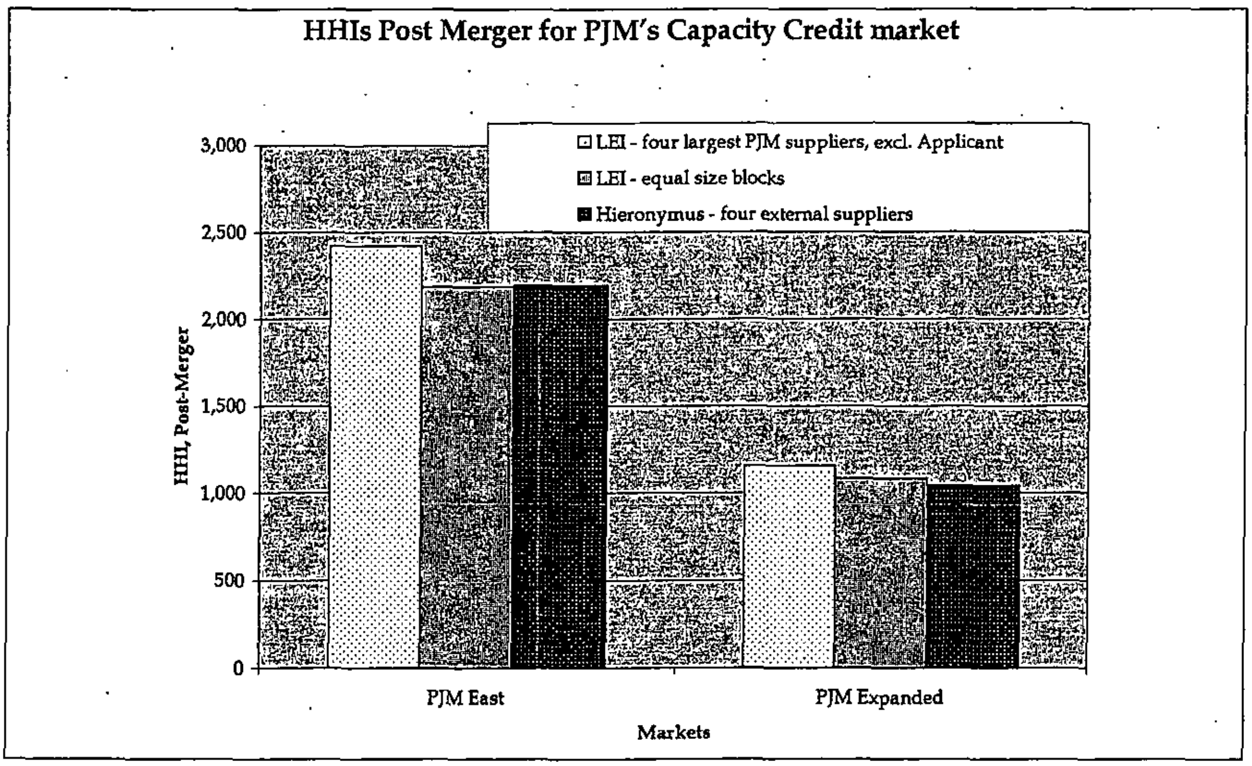
| PJM Expanded | | | PRE MERGER | | | | | | POST MERGER | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Season | Period | Destination Market Price | Exelon MW | Exelon Market Share | PSEG MW | PSEG Market Share | Market Size | HHI | Merged Entity MW | Merged Entity Market Share | HHI | HHI Change | Status of screen failure? |
| SUMMER | Extreme | $ 113 | 921 | 12.90% | 578 | 8.10% | 7,137 | 907 | 1,499 | 21.00% | 1,116 | 209 | Fail |
| SUMMER | Top 10% | $ 84 | 1,674 | 10.32% | 3,141 | 19.36% | 16,229 | 1,029 | 4,816 | 29.67% | 1,428 | 399 | Fail |
| SUMMER | Rest of Peak | $ 65 | 4,703 | 11.89% | 3,624 | 9.16% | 39,568 | 748 | 8,327 | 21.04% | 966 | 218 | Pass |
| WINTER | Top 10% | $ 120 | 1,208 | 10.62% | 2,098 | 18.46% | 11,368 | 966 | 3,306 | 29.08% | 1,358 | 392 | Fail |
| WINTER | Rest of Peak | $ 76 | 5,226 | 11.39% | 5,229 | 11.40% | 45,871 | 717 | 10,455 | 22.79% | 977 | 260 | Pass |
| SHOULDER | Top 10% | $ 83 | 1,770 | 10.03% | 3,332 | 18.87% | 17,652 | 993 | 5,101 | 28.90% | 1,372 | 378 | Fail |
| SHOULDER | Rest of Peak | $ 65 | 4,582 | 11.55% | 3,761 | 9.48% | 39,659 | 729 | 8,343 | 21.04% | 949 | 219 | Pass |

| Pre 2004 PJM | | | PRE MERGER | | | | | | POST MERGER | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Season | Period | Destination Market Price | Exelon MW | Exelon Market Share | PSEG MW | PSEG Market Share | Market Size | HHI | Merged Entity MW | Merged Entity Market Share | HHI | HHI Change | Status of screen failure? |
| SUMMER | Extreme | $ 113 | 921 | 15.92% | 578 | 10.00% | 5,784 | 1,203 | 1,499 | 25.92% | 1,521 | 318 | Fail |
| SUMMER | Top 10% | $ 84 | 1,674 | 13.38% | 3,141 | 25.11% | 12,512 | 1,325 | 4,816 | 38.49% | 1,997 | 672 | Fail |
| SUMMER | Rest of Peak | $ 65 | 1,867 | 8.76% | 3,624 | 17.00% | 21,321 | 891 | 5,491 | 25.75% | 1,189 | 298 | Fail |
| WINTER | Top 10% | $ 120 | 1,208 | 12.77% | 2,098 | 22.19% | 9,458 | 1,283 | 3,306 | 34.96% | 1,849 | 567 | Fail |
| WINTER | Rest of Peak | $ 76 | 2,110 | 7.81% | 5,229 | 19.35% | 27,019 | 903 | 7,339 | 27.16% | 1,205 | 302 | Fail |
| SHOULDER | Top 10% | $ 83 | 1,770 | 13.31% | 3,332 | 25.06% | 13,297 | 1,350 | 5,101 | 38.37% | 2,017 | 667 | Fail |
| SHOULDER | Rest of Peak | $ 65 | 1,922 | 9.19% | 3,761 | 17.99% | 20,911 | 939 | 5,683 | 27.18% | 1,270 | 331 | Fail |

| PJM East | | | PRE MERGER | | | | | | POST MERGER | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Season | Period | Destination Market Price | Exelon MW | Exelon Market Share | PSEG MW | PSEG Market Share | Market Size | HHI | Merged Entity MW | Merged Entity Market Share | HHI | HHI Change | Status of screen failure? |
| SUMMER | Extreme | $ 125 | 917 | 30.18% | 282 | 9.28% | 3,037 | 2,464 | 1,198 | 39.45% | 3,023 | 560 | Fail |
| SUMMER | Top 10% | $ 87 | 1,670 | 24.47% | 2,432 | 35.61% | 6,827 | 2,291 | 4,102 | 60.08% | 4,034 | 1,743 | Fail |
| SUMMER | Rest of Peak | $ 69 | 1,863 | 14.23% | 3,619 | 27.65% | 13,092 | 931 | 5,482 | 41.88% | 1,255 | 324 | Fail |
| WINTER | Top 10% | $ 123 | 1,204 | 22.16% | 1,524 | 28.05% | 5,433 | 1,194 | 2,728 | 50.21% | 1,662 | 468 | Fail |
| WINTER | Rest of Peak | $ 80 | 2,105 | 12.22% | 5,225 | 30.31% | 17,235 | 1,640 | 7,330 | 42.53% | 2,381 | 741 | Fail |
| SHOULDER | Top 10% | $ 86 | 1,765 | 22.12% | 2,874 | 36.03% | 7,978 | 1,284 | 4,639 | 58.14% | 1,930 | 646 | Fail |
| SHOULDER | Rest of Peak | $ 68 | 1,917 | 14.14% | 3,755 | 27.70% | 13,557 | 1,639 | 5,672 | 41.84% | 2,422 | 783 | Fail |

## Exhibit 21: Competitive Analysis Screen for PJM's Capacity Market: HHIs under LEI's Scenario 1 and Scenario 2

| | PRE-MERGER | | POST-MERGER | |
|---|---|---|---|---|
| | *PJM East* | *PJM Expanded* | *PJM East* | *PJM Expanded* |
| **Dr. Hieronymus (ICAP)** | | | | |
| *HHI* | *1,282* | *799* | *2,196* | *1,044* |
| HHI Change | | | 914 | 245 |
| | | | SCREEN FAILURE! | |
| **Scenario 1: LEI (UCAP-adjusted with imports allocated to four largest players, excl. Applicants)** | | | | |
| HHI | 1,512 | 908 | 2,422 | 1,156 |
| HHI Change | | | 911 | 248 |
| | | | SCREEN FAILURE! | |
| **Scenario 2: LEI (UCAP-adjusted with imports allocated in equal-sized blocks, incl. Applicants)** | | | | |
| HHI | 1,236 | 832 | 2,186 | 1,084 |
| HHI Change | | | 950 | 252 |
| | | | SCREEN FAILURE! | |



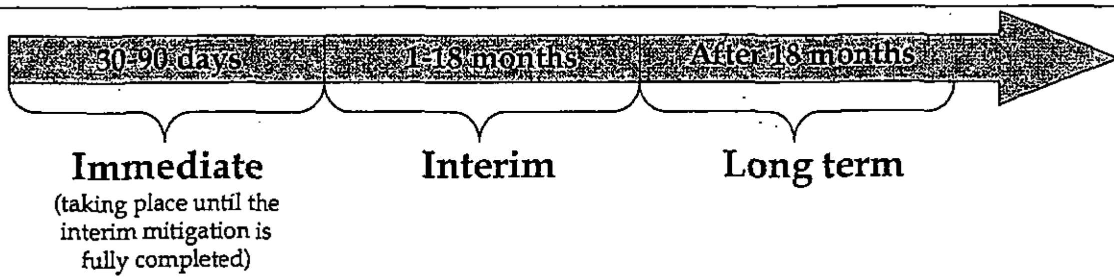


London Economics International LLC
717 Atlantic Ave, Unit 1A
Boston, MA 02111
www.londoneconomics.com

## Exhibit 22: Analyzing mitigation requirements for the PJM Capacity Credit market

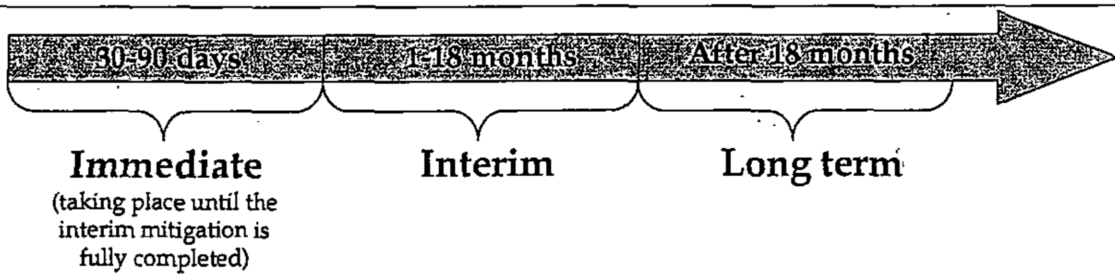
| | PRE-MERGER | | POST-MERGER WITH HIERONYMUS' MITIGATION | | POST-MERGER WITH LEI'S MITIGATION | | MINIMUM AMOUNT OF MITIGATION (MW) | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | PJM East | PJM Expanded | PJM East | PJM Expanded | PJM East | PJM Expanded | PJM East | | PJM Expanded | |
| **Dr. Hieronymus (ICAP)** | | | | | | | ICAP | *UCAP* | ICAP | *UCAP* |
| HHI | 1,282 | 799 | 1,380 | 997 | | | 5,300 | | 2,300 | |
| HHI Change | | | 98 | 198 | | | | | | |
| | | | SCREEN PASSES! | | | | | | | |
| **Scenario 1: LEI (UCAP-adjusted with imports allocated to four largest players, excl. Applicants)** | | | | | | | | | | |
| HHI | 1,512 | 908 | 1,621 | 1,114 | 1,611 | 1,007 | 5,385 | 4,579 | 7,550 | 6,643 |
| HHI Change | | | 109 | 206 | 99 | 99 | | | | |
| | | | SCREEN FAILURE! | | SCREEN PASSES! | | | | | |
| **Scenario 2: LEI (UCAP-adjusted with imports allocated in equal-sized blocks, incl. Applicants)** | | | | | | | | | | |
| HHI | 1,236 | 832 | 1,373 | 1,042 | 1,335 | 999 | 5,621 | 4,804 | 4,201 | 3,451 |
| HHI Change | | | 137 | 210 | 99 | 168 | | | | |
| | | | SCREEN FAILURE! | | SCREEN PASSES! | | | | | |

## Exhibit 23: Timeline of Applicants' proposed mitigation




| | Immediate | Interim | Long term |
|---|---|---|---|
| Peaking, coal and mid-merit capacity | Until interim mitigation is fully completed, Applicants bid the 2,900 into the PJM day-ahead at less than or equal to PJM cost-capped rates | Divestiture through sale of rights of 2,900 MW of energy and capacity from designated coal, mid-merit and peaking facilities in PJM East with contract terms ranging between 1 to 18 months | Divestiture of 2,900 MW of capacity (through outright sales). Included in this proposed divestiture is 1,000 MW of peaking capacity, 1,900 MW of mid-merit capacity (which includes at least 650 MW of coal-fired capacity) |
| Off-peak conditions | Until interim mitigation is fully completed, Applicants will bid all of their PJM East nuclear generation into the PJM day-ahead market at a price of zero | Divestiture through auction of firm entitlements to 25 MW blocks of energy but with shorter terms than the 3-year product in the long-term mitigation plan | "Virtual divestiture" of 2,600 MW of capacity (referred to as the "Baseload Mitigation Amount") through auctioning off long-term firm energy rights to baseload nuclear energy. Of the proposed 2,600 MW divestiture, 2,400 MW will be located in the PJM East with an additional 200 MW of capacity located in rest of PJM |

## Exhibit 23: Timeline of Applicants' proposed mitigation




| | Immediate | Interim | Long term |
|---|---|---|---|
| Peaking, coal and mid-merit capacity | Until interim mitigation is fully completed, Applicants bid the 2,900 into the PJM day ahead at less than or equal to PJM cost-capped rates | Divestiture through sale of rights of 2,900 MW of energy and capacity from designated coal, mid-merit and peaking facilities in PJM East with contract terms ranging between 1 to 18 months | Divestiture of 2,900 MW of capacity (through outright sales). Included in this proposed divestiture is 1,000 MW of peaking capacity, 1,900 MW of mid-merit capacity (which includes at least 550 MW of coal-fired capacity) |
| Off-peak conditions | Until interim mitigation is fully completed, Applicants will bid all of their PJM East nuclear generation into the PJM day-ahead market at a price of zero | Divestiture through auction of firm entitlements to 25 MW blocks of energy but with shorter terms than the 3-year product in the *long-term mitigation plan* | "Virtual divestiture" of 2,600 MW of capacity (referred to as the "Baseload Mitigation Amount") through auctioning off long-term firm energy rights to *baseload nuclear energy*. Of the proposed 2,600 MW divestiture, 2,400 MW will be located in the PJM East with an additional 200 MW of capacity located in rest of PJM |


London Economics International LLC
717 Atlantic Ave, Unit 1A
Boston, MA 02111
www.londoneconomics.com

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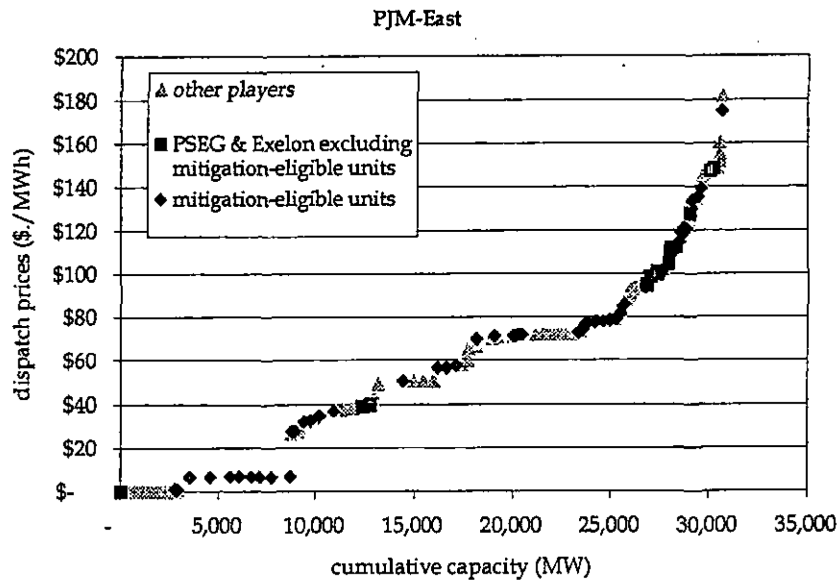
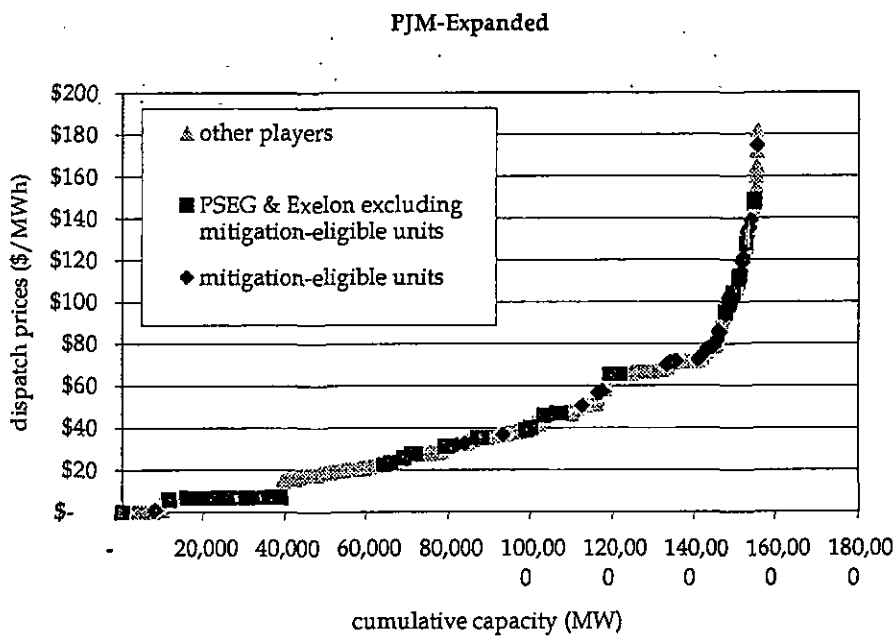
**Exhibit 24: Indicative supply curves for PJM East and Expanded PJM identifying assets earmarked for mitigation by the Applicants**



Met-Ed/Penelec/Penn Power Statement No. 3
EXHIBIT 3-B

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

RE: JOINT APPLICATION OF PECO ENERGY COMPANY
AND PUBLIC SERVICE ELECTRIC AND GAS
FOR APPROVAL OF THE MERGER OF
PUBLIC ENTERPRISE GROUP INCORPORATED
WITH AND INTO EXELON CORPORATION

DOCKET NO. A- 110550F0160