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Subject Company: NRG Energy, Inc.

On December 18, 2008, Exelon filed an application with the FERC with respect to the proposed transaction with NRG Energy, Inc. A copy of the FERC application together with its exhibits (other than Exhibit I, which is the S-4 filing with the SEC) is included in this filing.

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Exelon Corporation	)	Docket No. EC09-______

APPLICATION OF EXELON CORPORATION
UNDER SECTION 203 OF THE FEDERAL POWER ACT

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UNDER SECTION 203 OF THE FEDERAL POWER ACT

Pursuant to Section 203 of the Federal Power Act ("FPA") and Part 33 of the Commission's Regulations, Exelon Corporation and its subsidiaries that are public utilities subject to the Commission's jurisdiction (collectively, "Exelon")[1] hereby request that the Commission approve a transaction (the "Transaction") that is described in detail in Section III below, and which includes: (1) Exelon's acquisition of voting securities of NRG Energy, Inc. ("NRG Energy");[2] (2) Exelon's acquisition of control over NRG Energy and its subsidiaries that are public utilities subject to the Commission's jurisdiction (collectively, "NRG")[3]; and (3) the subsequent restructuring and consolidation of Exelon and NRG to establish a more efficient corporate structure for the combined company. As described in more detail below, the proposed Transaction meets the Commission's standards for determining when a transaction is consistent with the public interest and as a result can be approved without a hearing. Exelon requests that the Commission grant its approval no later than May 1, 2009.

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1 The Exelon entities subject to the Commission's jurisdiction are identified below in Exhibit B of this Application.

2 As described in more detail in Section III, Exelon is hopeful that it eventually will reach a negotiated agreement with NRG Energy that could result in an alternative transaction structure where NRG Energy purchases voting securities of Exelon instead of having Exelon purchase voting securities of NRG Energy. Exelon requests approval of this alternative structure as well.

3 The NRG entities subject to the Commission's jurisdiction are identified below in Exhibit B of this Application.

I. INTRODUCTION

The Transaction provides for the combination of two companies with complementary assets that should allow for increased value to the benefit of each company, their customers and their shareholders. Among the expected benefits of the Transaction are: (1) increased generation efficiencies resulting from economies of scale; (2) cost savings from operational synergies; and (3) fuel and geographic diversification. These benefits should allow the combined company to reduce its costs and increase the competitiveness of its generation capacity, which is in the public interest.

To date, NRG's management has not recognized the benefits of the Transaction, and has rejected the offer to purchase NRG that Exelon made on October 19, 2008. This rejection has led Exelon to present a tender offer directly to NRG's shareholders. Exelon believes that a negotiated agreement with NRG would be preferable, and will continue to seek such an agreement with NRG management. To the extent that agreement is not reached, however, Exelon intends to continue pursuing its tender offer and to complete the Transaction.

The fact that there currently is not an agreement between Exelon and NRG's management should not affect the Commission's analysis of the Transaction. Exelon's offer is being made directly to NRG's shareholders, and ultimately it is NRG's shareholders who will decide whether that offer should be accepted. Exelon is not requesting that the Commission take sides or make any determination whether Exelon's offer should be accepted. Maintaining neutrality in this context requires the Commission to process this Application under its ordinary procedures. If the Commission were to decline to act until NRG's management agreed, management effectively would have a veto over shareholders' decisions to tender their shares to Exelon, because without the

Commission's authorization Exelon cannot purchase more than 9.9% of NRG's voting shares. Processing an application under normal procedures is the course the Commission previously has taken when faced with a non-consensual corporate transaction. *See Kansas City Power & Light Co.*, 53 FERC ¶ 61, 097 at 61,282-84 (1990). Such a course of action also is consistent with the longstanding federal policy that favors neutrality between transactions supported by management and tender offers not supported by management, and agencies have implemented that policy by processing merger applications without regard to whether they have been approved by incumbent management.

Moreover, the recent amendments to FPA Section 203 require a ruling on an application by a holding company, such as Exelon, to purchase the securities of another holding company, such as NRG, in 180 days. Nothing in these amendments suggests that this requirement ceases to apply simply because the holding company's management objects to shareholders being allowed to sell their securities to the applicant.[4]

Although the combination of Exelon and NRG will create the largest electric company in the United States, there is not a significant geographic overlap between the two companies' generation, and thus no significant competition concerns are raised by the Transaction. Further, Exelon has proposed a "clean sweep" divestiture of all of NRG's generation capacity in the PJM East market and of all of Exelon's generation capacity in the ERCOT market, which are the only two markets where there is any material overlap of generation assets. With these clean sweep divestitures, there can be no question of any adverse impact on competition resulting from the Transaction.

4 FPA Section 203(a)(5) does allow the Commission to take an additional 180 days to evaluate a transaction for good cause if the extra time is necessary to process the application. Nothing in Section 203(a)(5) suggests, however, that extra time should be required for a nonconsensual transaction.

Nor does the Transaction implicate any of the other public interest issues considered by the Commission as part of its review of proposed mergers. Exelon is making the standard rate commitments required by the Commission to ensure that no customers with cost-based rates suffer adverse rate consequences from the Transaction. Neither the Commission nor any state utility commission will have its jurisdiction affected by the Transaction. Exelon also is making commitments to ensure that no cross-subsidization concerns are raised. As added protection against any prohibited pledge or encumbrance of utility assets or any inappropriate cross subsidization involving captive utility customers, Exelon is proposing ring-fencing commitments which will take effect upon closing of the Transaction.

In sum, with the commitments made by Exelon, it is clear that the Transaction is consistent with the public interest, as required by FPA Section 203. Exelon requests that the Commission process this Application under its standard procedures, and approve the Transaction no later than May 1, 2009, without conducting an evidentiary hearing.

II. DESCRIPTION OF EXELON AND NRG

A. Exelon

Exelon is a public utility holding company that, through its subsidiaries, is one of the nation's largest electric utilities. Exelon distributes electricity to approximately 5.4 million customers in Illinois and Pennsylvania, and natural gas to 480,000 customers in the Philadelphia area. Exelon's operations include energy generation, power marketing and energy delivery. Exelon has one of the industry's largest portfolios of electricity generation capacity, with a nationwide reach and strong positions in the Midwest and

Mid-Atlantic. Exelon operates the largest nuclear fleet in the United States. Exelon operates through its principal subsidiaries—Commonwealth Edison Company ("ComEd"), PECO Energy Company ("PECO"), and Exelon Generation Company, LLC ("Exelon Generation") – as described below.

1. ComEd and PECO

(a) ComEd

ComEd is engaged principally in the purchase, transmission, distribution and sale of electricity to a diverse base of residential, commercial, industrial and wholesale customers in Northern Illinois. ComEd's retail service territory has an area of approximately 11,300 square miles and an estimated population of eight million. The service territory includes the City of Chicago, an area of about 225 square miles with an estimated population of three million. ComEd has approximately 3.8 million customers.

ComEd does not own any generation. Beginning in January 2007, ComEd began procuring all of its energy requirements for retail customers from market sources pursuant to the Illinois Commerce Commission ("ICC") approved procurement auction in 2006.[5] Approximately one-third of ComEd's contracts that resulted from the 2006 auction expired in May 2008, another one-third will expire in May 2009, and the remaining contracts will expire in May 2010. Approximately 35% of the contracted supply from the 2006 auction came from Exelon Generation. Suppliers, including Exelon Generation, were limited to winning no more than 35% in either the fixed price section or the hourly price section of the auction.[6]

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[5] The results of the hourly price section of the auction were not approved by the ICC, so in accordance with the approved process, ComEd purchased that supply from the PJM spot market.

[6] Subsequent to the 2006 auction, and in accordance with the auction rules, Exelon Generation purchased 10 tranches, or 2.7% of the contracted supply, from a counterparty. The supply commitment for these tranches ends in May, 2009.

In 2007, the Illinois Legislature enacted new legislation that established a new competitive process for procurement to be managed by the Illinois Power Agency ("IPA") and overseen by the ICC in accordance with electricity supply procurement plans approved by the IPA. Pursuant to that legislation, ComEd entered into a five-year financial swap agreement with Exelon Generation that provides for 1,000 megawatts (MW) of power in the first year of the agreement (June 1, 2008 through May 31, 2009), 2,000 MW in the second year and 3,000 MW in the third through fifth years. In the interim period between the enactment of this legislation and its implementation by the IPA, ComEd submitted to the ICC, and the ICC approved, a procurement plan for ComEd to secure its remaining requirements, *i.e.*, net of the swap agreement and the auction contracts, for power and other ancillary services for the period from June 2008 to May 2009. ComEd retained an independent third party to conduct a competitive RFP process and as a result of that process executed supply agreements pursuant to this approved plan in March 2008.

In July 2008, ComEd submitted a five-year forecast to the IPA, and the IPA developed a procurement plan for approval by the ICC to procure ComEd's remaining requirements for energy in periods subsequent to May 2009. This process will be repeated on an annual basis in the future.[7]

[7] In addition, ComEd makes a small amount of purchases from Qualifying Facilities ("QFs") under the Public Utilities Policy Act of 1978 ("PURPA").

(b) PECO

PECO is engaged principally in the purchase, transmission, distribution and sale of electricity to residential, commercial and industrial customers in southeastern Pennsylvania and in the purchase, distribution and sale of natural gas to residential, commercial and industrial customers in the Pennsylvania counties surrounding the City of Philadelphia. PECO provides electric delivery service in an area of approximately 2,000 square miles, with a population of approximately 3.8 million. Natural gas service is supplied in an approximate 1,900 square mile area in southeastern Pennsylvania adjacent to Philadelphia, with a population of approximately 2.4 million. PECO delivers electricity to approximately 1.6 million customers and natural gas to approximately 480,000 customers.

Electric utility restructuring legislation was adopted in Pennsylvania in December 1996. Pennsylvania permits competition by alternative generation suppliers for retail generation supply while transmission and distribution service remains fully regulated. Pennsylvania allowed customers to choose an alternative electric generation supplier; imposed caps on rates during a transition period; and authorized the collection of competitive transition charges from customers to recover costs that might not otherwise be recovered in a competitive market.

Under Pennsylvania legislation, PECO is required to provide generation services to customers who do not or cannot choose an alternative supplier. PECO has provider of last resort ("POLR") obligations to provide generation services (*i.e.*, full requirements) to those customers who do not take service from an alternative generation supplier or who choose to come back to the utility after taking service from an alternative supplier.

PECO does not own any generation, but instead purchases the power needed to satisfy its POLR obligations from Exelon Generation.[8] The contract between PECO and Exelon Generation expires at the end of 2010. To meet its POLR obligations beginning in 2011, PECO intends to purchase power through a competitive-procurement process approved by the Pennsylvania Public Utility Commission ("PAPUC"), including potentially from Exelon Generation.

(c) Transmission Services

ComEd and PECO have both placed their transmission systems under the operational control of PJM Interconnection, L.L.C. ("PJM"), which is the independent system operator and the Commission-approved RTO for the Mid-Atlantic and Midwest region in which it operates. PJM is the transmission provider under, and the administrator of, the PJM Open Access Transmission Tariff ("PJM Tariff"), operates the PJM Interchange Energy Market and a Forward Capacity Market, and conducts the day-to-day operations of the bulk-power system of the PJM region. Under the PJM tariff, transmission service is provided on a region-wide, open-access basis using the transmission facilities of the PJM members at rates based on the costs of transmission service. ComEd and PECO have each filed a transmission cost-based "cost of service" at the Commission, which PJM then uses to establish the charges that it imposes for transmission service.

(d) Gas Services

Exelon's regulated gas services business is conducted solely by PECO, and not by ComEd or any other Exelon company. PECO's gas-sales and gas-transportation revenues

8 PECO also purchases a small amount of power from QFs under PURPA.

are derived pursuant to rates regulated by the PAPUC. Neither PECO nor any other Exelon company owns any interstate natural gas facilities that are subject to the Commission's jurisdiction under the Natural Gas Act. However, PECO does operate an intrastate natural gas distribution system in four counties that surround, but do not include, the city of Philadelphia. Its gas service area includes several third-party industrial customers and small generators, only a few of which use natural gas for generation other than as start-up fuel or backup. The few that are gas-fired generators are Merck (28 MW), Kimberly Clarke (55 MW), Crozier Chester Hospital (3.1 MW) and Hills at White Marsh (2 MW).

PECO's customers have the right to choose their gas suppliers or purchase their gas supply from PECO at cost. Approximately 30% of PECO's current total yearly throughput is supplied by third parties. Gas-transportation service is provided on an open-access basis and remains subject to regulation by the PAPUC.

2. Exelon Generation

Exelon's generation business is conducted by Exelon Generation, which was created in 2001, when Exelon restructured its business operations following the Unicom-PECO merger. Exelon Generation combines its large generation fleet with an experienced wholesale power marketing operation. Exelon Generation owns, or controls through long-term contracts, generation assets in the Northeast, Mid-Atlantic, Midwest, Southeast, South Central and Texas regions. For 2009, Exelon Generation is projected to own generation assets with an aggregate net capacity of 24,509 MW. In addition, Exelon Generation is projected to control another 5,543 MW of capacity through long-term contracts in 2009. A listing of Exelon Generation's generation assets (including long-term contracts) is attached as Exhibit J-3 to Dr. Hieronymus' testimony.

Exelon Generation's wholesale power marketing unit, Power Team, a major wholesale marketer of energy, uses Exelon Generation's energy generation portfolio, transmission rights and expertise to ensure delivery of energy to Exelon Generation's wholesale customers under long-term and short-term contracts, including a contract for the load requirements of PECO, and contracts for a portion of ComEd load requirements. Power Team markets any remaining energy in the wholesale bilateral and spot markets.

B. NRG

As noted above, currently NRG's management opposes the Transaction, and NRG is not one of the applicants under this Application. The following description is based on public information released by NRG and is accurate to the best of Exelon's knowledge.[9]

NRG, is a wholesale power generation company with a significant presence in major competitive power markets in the United States. NRG is engaged in the ownership, development, construction and operation of power generation facilities, the transacting in and trading of fuel and transportation services, and the trading of energy, capacity and related products in the United States and select international markets.

Within the United States, NRG is projected to own 26,247 MW of generation capacity in 2009. NRG also is projected to control an additional 600 MW of capacity through long-term purchases. A listing of NRG's generation assets (including long-term contracts) is attached as Exhibit J-4 to Dr. Hieronymus' testimony.

9 Exelon does not know whether the information published by NRG may be inaccurate or whether there is additional material nonpublic information regarding NRG.

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III. DESCRIPTION OF THE TRANSACTION

A. Background of the Transaction

On October 19, 2008, Exelon delivered a letter to NRG setting forth a proposal for a business combination of Exelon and NRG. Under this proposal, Exelon would acquire all of the outstanding shares of NRG common stock at a fixed exchange ratio of 0.485 Exelon shares for each NRG common share. This offer represented a 37 percent premium to NRG stockholders above NRG's closing price on October 17, 2008.

NRG did not respond immediately to Exelon regarding this proposed offer. Instead, on October 20, 2008, NRG issued a press release confirming receipt of Exelon's proposal to acquire all of the outstanding shares of NRG common stock, indicating that NRG's board of directors was reviewing Exelon's proposal with its advisors and advising NRG stockholders to take no action at that time pending the board's review. However, on November 9, 2008, NRG issued a press release stating that it was rejecting NRG's proposed offer for a number of reasons.

On November 12, 2008, Exelon commenced a tender offer for NRG's outstanding common shares. If the tender offer is successful and NRG's management remains opposed to the Transaction (and if all necessary regulatory approvals are obtained), Exelon expects to implement the Transaction notwithstanding the opposition of NRG's management.

Exelon continues to believe that a negotiated agreement with NRG is preferable and would provide significant benefits for the combined company. For one thing, a negotiated agreement would allow the Transaction to be implemented pursuant to a structure, described more fully below, that might reduce the amount of NRG debt required to be refinanced upon the completion of the Transaction. For another, a negotiated agreement with NRG would benefit from the participation of officers and employees of NRG with intimate knowledge of the company, which should allow for the Transaction to be structured in a way to best capture the value of NRG for the combined company.

As a result, Exelon will continue its efforts to reach a negotiated agreement with NRG. At the present, however, Exelon is pursuing the Transaction without the cooperation of NRG's management.

B. Description of the Transaction

As noted above, Exelon hopes eventually to reach a negotiated agreement with NRG. Depending on whether or not such an agreement is reached, the various steps required to effectuate the combination could differ. The possible alternative deal structures are described in more detail below.

Regardless of the interim steps and the ultimate form of the Transaction, the substance of the Transaction that is relevant to the Commission's review under Section 203 of the Federal Power Act will be the same whether or not Exelon reaches a negotiated agreement with NRG's management. In particular, regardless of the form, the following are the key substantive principles of the Transaction:

1. The overall operations of Exelon and NRG will be consolidated under the control of Exelon.
2. The operations of NRG's generation facilities will be consolidated with the operations of Exelon Generation, which is an unregulated company with market-based rate authority that owns Exelon's generation assets. Regardless of the ultimate corporate form, where NRG Energy may or may not be consolidated with Exelon Generation, the generation assets of NRG and Exelon Generation will be operated on a combined basis.
3. Exelon's two traditional franchised utilities – PECO and ComEd – will continue to operate separately from the unregulated businesses, including the Exelon Generation business. The Transaction will not involve any transfer of assets between PECO or ComEd and any other Exelon or NRG company, nor will PECO or ComEd issue any debt or securities, assume any liabilities, or enter into any contracts in connection with the Transaction. NRG does not own any traditional franchised utilities.

4. Sufficient generation capacity will be divested, as described more fully below, to address any market power concerns.
5. Sufficient rate commitments will be made, as described more fully below, to hold cost-based customers harmless from any adverse rate impacts of the Transaction.
6. Sufficient cross-subsidization commitments will be made, as described more fully below.

C. Potential Mechanisms for Implementing the Transaction

1. Transaction Mechanism Under Exelon's Tender Offer

Under the terms of the tender offer, Exelon, through Exelon Xchange, a wholly-owned subsidiary created for purposes of the Transaction, is offering to exchange 0.485 of a share of Exelon common stock (the "exchange ratio") for each share of NRG common stock that is validly tendered and not withdrawn prior to the expiration date upon the terms and subject to the conditions contained in the prospectus/offer, which is attached to this Application as Exhibit I. The offer is subject to a number of conditions, including a condition that at least 50% of the NRG common stock must be tendered and not withdrawn at the time the offer expires. The current expiration date of the offer is January 6, 2009. However, this expiration date is subject to extension. Exelon will not consummate the Transaction until it has received all necessary regulatory approvals, including the Commission's approval under FPA Section 203, and other conditions of the offer have been met.

The tender offer is the first step in Exelon's acquisition of NRG and is intended to facilitate the acquisition of all shares of NRG common stock. After Exelon Xchange acquires NRG common stock pursuant to the offer, Exelon and Exelon Xchange will hold at least a majority of NRG's common stock. As soon as possible after completion of the tender offer, Exelon will seek to have NRG consummate a second-step merger of Exelon Xchange or another wholly-owned subsidiary of Exelon with and into NRG. The purpose of the second-step merger is to acquire all shares of NRG common stock not tendered and exchanged in the offer. Pursuant to the terms of the second-step merger, each remaining share of NRG common stock (other than shares of NRG common stock owned by Exelon, Exelon Xchange or NRG or held by NRG stockholders who perfect appraisal rights under Delaware law, to the extent available) would be converted into the right to receive the same number of shares of Exelon common stock as paid in the tender offer.

The second-step merger will be followed by the merger of NRG with and into Exelon or a wholly-owned subsidiary of Exelon (the "forward merger"), unless Exelon is able to obtain a legal opinion at the time of the second-step merger that the tender offer and the second-step merger, taken together and without the consummation of the forward merger, will qualify as a reorganization within the meaning of Section 368(a) of the Internal Revenue Code.

In addition, there will internal reorganizations within the corporate structure of the combined company. These reorganizations will be undertaken to facilitate the consolidation of the generation and power marketing businesses of NRG and Exelon Generation and will be consistent with the substance of the Transaction, including the protections for PECO and ComEd, that are set forth in the six principles described above.

Based on certain assumptions regarding the number of shares of NRG common stock to be exchanged, Exelon estimates that if all shares of NRG common stock are exchanged pursuant to the offer and the second-step merger, former NRG stockholders would own, in the aggregate, 16% of the outstanding shares of Exelon common stock.

2. Transaction Mechanism Under Negotiated Agreement

If Exelon is successful in reaching a negotiated agreement with NRG, Exelon may decide not to acquire NRG shares pursuant to the approach described above, and instead could use alternative methods for structuring the Transaction. For example, Exelon may pursue a structure whereby Exelon is merged into NRG, with NRG as the surviving corporation, and NRG then being renamed as Exelon Corporation, followed by the election of existing Exelon directors and officers to corresponding positions in the new Exelon Corporation. Such a structure might allow Exelon to reduce the amount of NRG debt that must be refinanced in connection with the Transaction.

In the course of any negotiations with NRG, Exelon also would be open to further suggestions from NRG regarding other aspects of the corporate structure of the combined company. This could lead to other changes in the internal corporate structure of the combined company. In addition, it is possible that any negotiated agreement with NRG management would include a change in the form and/or amount of consideration paid to NRG shareholders. Again, any such changes would be consistent with the six principles described in Section III.B. above.

Exelon therefore requests that the Commission approve the Transaction, whether it is structured as currently contemplated in Exelon's tender offer as described in Section III.C.1 above, or under alternative structures if Exelon reaches a negotiated agreement with NRG management, provided that the negotiated Transaction complies with the six principles described in Section III.B above.

D. Anticipated Benefits of the Transaction

Exelon believes that the Transaction will provide a number of benefits, including the following:

- *Increased Scope and Scale* – The Transaction will create a combined company with increased scale and scope in generation. The combined company would constitute the largest power company in the U.S. by assets, market capitalization, enterprise value and generation capacity. The combined company is expected to have an enterprise value of approximately $60 billion and a market capitalization of $40 billion.
- *Increased Generation Efficiency* – Exelon believes that significant efficiencies of scale would be realized from the combination of the generation fleets of Exelon and NRG.
- *Synergies* – Although no assurance can be given that any particular level of cost savings and other synergies will be achieved, based on publicly available information, Exelon management believes that the Transaction may result in annual estimated synergies of approximately $180 to $300 million through the combination of operational, financial and service capabilities, before giving effect to costs to achieve the synergies, increased interest expense in connection with the refinancing of existing NRG indebtedness and any adjustments that may result from due diligence investigation.
- *Fuel and Geographic Diversification* – The combined company would have a more highly diversified mix of generation capacity with a presence in four major domestic competitive power generation regions and a diversified fuel mix using uranium, natural gas, coal and oil.
- *Enhanced Ability to Pursue Capital-Intensive Projects* – Exelon believes that the combined company's assets, enterprise value and market capitalization will enable Exelon to pursue more multi-year, capital intensive projects than would be possible absent the acquisition of NRG. This is particularly important with respect to the improved ability to finance the construction and operation of new nuclear facilities.

IV. THE COMMISSION SHOULD PROCESS THIS APPLICATION UNDER ITS STANDARD PROCEDURES FOR EVALUATING SECTION 203 APPLICATIONS

Exelon recognizes that this Transaction differs from the typical transactions reviewed by the Commission under FPA Section 203 in that, currently, management of NRG has rejected Exelon's proposal and opposes Exelon's tender offer. That fact, however, should affect neither the Commission's obligation to promptly review the proposed Transaction nor the process by which the Commission considers this Application. Exelon has made an offer directly to NRG's shareholders proposing to acquire their shares at what Exelon believes to be an attractive price. However, Exelon will not be able to follow through on its offer to purchase NRG shares, and NRG shareholders will not be able to sell their shares, until such time as the Commission approves this Application.

In order to give NRG shareholders the opportunity to tender and sell their shares if they so wish, the Commission should promptly review and approve the proposed Transaction, following the same procedures and applying the same standards that it would apply if NRG's management had agreed to the proposed Transaction. Exelon is asking for no more and no less. Otherwise, NRG's shareholders might never even be given the opportunity to vote for the proposed Transaction by selling their shares.

By following its standard policies and procedures in processing this Application, the Commission would maintain its policy of neutrality between acquisition proposals that are supported by incumbent management and those that are not. Because Exelon cannot purchase more than 9.9% of NRG's voting shares without the Commission's authorization, a failure to timely process this Application would infringe on the right of NRG's shareholders – who are the owners of NRG – to decide for themselves whether to exchange their stock under the terms of Exelon's offer.

That Congress intended for the Commission to process proposals for the acquisition of voting shares from shareholders without regard to management's agreement is made evident by the changes to FPA Section 203 that were implemented by the Energy Policy Act of 2005 ("EPAct"). The Commission now is required under

Section 203(a)(2) to authorize the purchase by a holding company that owns an electric utility (such as Exelon) of the securities with a value in excess of $10 million of a holding company that owns an electric utility (such as NRG). Nothing in Section 203(a)(2) suggests in any fashion that management of the company whose securities are being acquired has any role whatsoever in the process, much less that the purchase must be negotiated with or agreeable to that management. Nor has the Commission in the past interpreted Section 203(a)(2) as requiring management's acquiescence in the purchase of securities. *See, e.g. Horizon Management, Inc.* 125 FERC ¶ 61,209 (2008) (clarifying circumstances under which Commission approval is required for the purchase of securities of electric utilities and electric utility holding companies).

Moreover, Congress made clear in its EPAct amendments to Section 203 that the Commission must "adopt procedures for the expeditious consideration of dispositions, consolidations, or acquisitions under this section." FPA Section 203(a)(5). Congress also required the Commission to process all Section 203 applications in 180 days (subject to a 180-day extension). *Id.* Nothing in Section 203(a)(5) suggests that expeditious treatment is not required for transactions that are not supported by the management of the company being acquired. Thus, the EPAct amendments to Section 203 make clear Congress' intent that the Commission must process Exelon's application expeditiously, as it would any other application, even though the Transaction currently is not supported by NRG's management.

Even before the enactment of the EPAct amendments the Commission held, when faced with a proposed transaction that was opposed by the management of one of the parties, that it has the duty to process Section 203 applications when they are received, regardless of whether both parties have agreed to the transaction. *See Kansas City Power*

& Light Co., 53 FERC ¶ 61, 097 at 61,282-84. In that case, the Commission was presented with arguments that it should not process a Section 203 application unless the proposed transaction had been approved by both parties. The Commission rejected these arguments as follows:

> We find that an acquiree's opposition to a proposed merger *in and of itself* is not enough to cause us to look unfavorably upon an applicant's request for section 203 approval, and thus we deny KG&E's motion to reject KCP&L's filing. As discussed *supra*, the Commission must discharge its statutory obligation to consider whether or not to approve jurisdictional mergers, in each case determining whether the transaction is "consistent with public interest," and in each case ensuring the "maintenance of adequate service and proper coordination." *We find no statutory authority or judicial precedent which would require us to distinguish between negotiated mergers, and those opposed by the proposed acquiree's board of directors. The Commission will entertain section 203 applications on a case-by-case basis, in each instance analyzing the proposed transaction in order to determine whether the outcome would be consistent with the public interest.*

Id. at 61,283 (second emphasis added). The Commission went on to explain that it was going forward with its processing of KCPL's application in order to remain neutral in the proposed tender offer:

> [W]e stress that our action today should not be construed as favoring, or disfavoring, KCP&L's tender offer. The ultimate question before the Commission is not whether KCP&L's proposal will or should be consummated. Rather, the question is whether this proposed merger, if consummated, is consistent with the public interest.

Id. at 61,284.

The Commission's *KCPL* decision is consistent with the federal policy that has been in existence at least since the passage of the Williams Act in 1968.[10] Although the specific provisions of the Williams Act relate to the provision of adequate information to

10 The Williams Act added new Sections 13(d), 13(e), 14(d), 14(e) and 14(f) to the Securities Exchange Act of 1934. Williams Act Pub. L. No. 90-439, 82 Stat. 454 (1968) et seq. (codified at 15 U.S.C. 78m(d)-(e) and 78n(d)-(f)).

shareholders to inform their voting, federal courts have found that the Act, and its legislative history, evidences a broad federal policy that shareholders should be given the opportunity to make decisions on tender offers and that this opportunity should not be frustrated by management. *See Edgar v. MITE Corp.*, 457 U.S. 624, 634 (1982) ("We, therefore, agree with the Court of Appeals that Congress sought to protect the investor not only by furnishing him with the necessary information but also by withholding from management or the bidder any undue advantage that could frustrate the exercise of an informed choice"); *Piper v. Chris-Craft Indus., Inc.*, 430 U.S. 1, 29 (1977) ("Congress was indeed committed to a policy of neutrality in contests for control…. Neutrality is, rather, but one characteristic of legislation directed toward a different purpose – the protection of investors").

The goal of this federal policy of neutrality is to protect shareholders and increase corporate efficiency. To the extent that a company's management is able to use federal regulatory processes to delay or defeat a superior proposal for corporate ownership, that is not in the public interest. Instead, a policy of neutrality allows shareholders to decide for themselves whether or not an offer to purchase their shares should be accepted over the opposition of management.

In the regulatory context, a policy of neutrality means that the reviewing agency should process and evaluate a proposed transaction in the same fashion whether or not the management of the entity being acquired has acquiesced to the transaction. If the reviewing agency were to delay its evaluation or to apply a more onerous standard simply because the transaction has not been agreed-to by management, then the attendant delay or more onerous requirements favor the existing management for reasons that are unrelated to the merits of the transaction. To the extent that this delay or burden causes the transaction to falter, then shareholders are denied the ability to decide whether the transaction is appropriate and should be consummated.

The Commission's policy of neutrality in *KCPL* is consistent with the policy of other federal agencies that have addressed the question:

- The FTC adopted a neutral policy toward nonconsensual transactions in its statement of basis and purpose accompanying its final rules implementing its review of proposed mergers under the Hart-Scott-Rodino Act (which also are applicable to reviews conducted by the Department of Justice ("DOJ")), stating that although the interests of the acquiring and acquired person are divergent in a nonconsensual transaction, "those conflicting interests alone would not appear to justify a rule which would give an advantage to an acquired company resisting the takeover." Premerger Notification: Reporting and Waiting Period Requirements, 43 Fed. Reg. 33,450, 33,514 (1978). In order to ensure neutrality, it explained that, unlike consensual acquisitions, there are concerns that "an apathetic or hostile issuer could frustrate the transaction merely by neglecting to file notification," or delay of agency clearance could give the issuer time to defeat the offer and could affect the acquired company's stock to the detriment of the offer. *Id.* at 33483-84. As a result, in nonconsensual transactions, the FTC and DOJ base their review timelines on the filings made by the acquirer without regard to the extent that the entity opposing the transaction complies with the applicable filing requirements.
- The FCC, in its Policy Statement in *In re Tender Offers and Proxy Contests*, stated that: "Our third objective is to assure, to the fullest extent possible, that the procedures prescribed in this proceeding promote strict governmental neutrality in takeover contests." 59 Rad. Reg. 2d (P&F) 1536, P 6 (1986). In cases where incumbent management has argued against the transfer of its license to an acquirer, the FCC has been committed to "scrupulously follow [its] established procedures" to ensure neutrality, which "demands that the Commission's actions not favor any party in the contest for corporate control." *ITT Corp.*, 13 FCC Rcd 5861 (1997).
- The Federal Reserve Board, in evaluating a proposed nonconsensual acquisition of a bank, stated that: "The [BHC] Act does not draw any distinction between acquisitions that are agreed to between the parties and those where, as here, there is no agreement." *The Bank of New York Co., Inc.*, 74 Fed. Res. Bull. 257, 259 (1988). *See also Wells Fargo & Co.*, 82 Fed. Res. Bull. 445, 457 (1996) (approving takeover of competitor bank without discussion of any distinct approval process for nonconsensual acquisitions).

It thus is clear that the path that the Commission followed in the KCPL proceeding was consistent with the broad federal policy objectives of not allowing incumbent management to frustrate or delay the ability of shareholders to exercise their rights. That path is required even more today, after the EPAct amendments in 2005. The Commission should again adopt a posture of neutrality and process this Application in the ordinary course.

V. THE TRANSACTION IS CONSISTENT WITH THE PUBLIC INTEREST

Section 203(a)(4) of the FPA provides that "the Commission shall approve the proposed disposition . . . if it finds that the proposed transaction will be consistent with the public interest." Exelon need not show that a transaction positively benefits the public interest, but rather simply that it is "consistent with the public interest," *i.e.* that the transaction does not harm the public interest. *See*, *e.g.*, *Texas-New Mexico Power Co.*, 105 FERC ¶ 61,028 at P 23 & n.14 (2003) (citing *Pacific Power & Light Co. v. FPC*, 111 F.2d 1014, 1016-17 (9th Cir. 1940)).

In determining whether a proposed disposition of jurisdictional facilities is consistent with the public interest, the Commission evaluates the impacts of the proposed disposition on competition, rates and regulation. *See Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement*, Order No. 592, FERC Stats. & Regs. ¶ 31,044 at 30,111 (1996), *order on recons.*, Order No. 592-A, 79 FERC ¶ 61,321 (1997) ("Merger Policy Statement"). When considering impacts on competition, the Commission reviews both horizontal competition issues resulting from increases in concentration in energy and capacity markets and vertical competition issues resulting from increases in the ability or incentive to leverage control over electric transmission and natural gas transportation facilities to enhance revenues in generation markets. *See Revised Filing Requirements Under Part 33 of the Commission's Regulations*, Order No. 642, FERC Stats. & Regs. ¶ 31,111 at 31,872 (2000) ("Order No. 642").

In addition, the Commission also must determine under FPA § 203(a)(4) that a proposed transaction will not result in cross-subsidization of a non-utility associate company by a traditional utility company, or the pledge or encumbrance of utility assets for the benefit of an associate company, unless that cross-subsidization, pledge, or encumbrance will be consistent with the public interest. The standards for evaluating whether an improper cross-subsidization will result are set forth in Order Nos. 669, 669-A and 669-B,[11] and were recently clarified in the Commission's Supplemental Merger Policy Statement. *FPA Section 203 Supplemental Policy Statement*, FERC Stats. & Regs. ¶ 31,253 (2007) ("Supplemental Merger Policy Statement").

As demonstrated below, the Transaction satisfies all of these standards. Therefore, it is consistent with the public interest and should be approved.

A. <u>Horizontal Competition Issues</u>

Exelon has retained Dr. William H. Hieronymus to analyze the horizontal competition issues resulting from the Transaction. Dr. Hieronymus' testimony addressing these issues is attached as Exhibit J to this Application. He concludes that, with Exelon's proposed divestitures, the Transaction will not raise any horizontal market power concerns.

To start his analysis, Dr. Hieronymus has determined how much generation Exelon and NRG own or control in each relevant geographic market. Generally, Dr.

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11 *Transactions Subject to FPA Section 203*, Order No. 669, FERC Stats. & Regs. ¶ 31,200 ("Order No. 669"), *order on reh'g*, Order No. 669-A, FERC Stats. & Regs. ¶ 31,214 ("Order No. 669-A"), *order on reh'g*, Order No. 669-B, FERC Stats. & Regs. ¶ 31,225 (2006) ("Order No. 669-B").

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Hieronymus considered that the relevant geographic market consists of the RTO/ISO where the generation is located. For those parts of the country where there is not an RTO/ISO that meets the criteria established by the Commission to be considered a single relevant geographic market, Dr. Hieronymus has used the balancing authority where the generation is located. The following table shows the results of this initial screen, which is taken from Table 1 of Exhibit J-1.

GENERATION OWNED OR CONTROLLED BY EXELON AND NRG (MW)

Market	Exelon	NRG
PJM	23,698	1,644
ISO-New England	178	2,204
New York ISO	0	4,051
ERCOT	3,405	13,269
Cal ISO	0	2,633
Midwest ISO	1,043	0
Nevada Power	0	51
CSW	795	0
Entergy	853[12]	2,994
Southern Company	933	0
Total	30,052[13]	26,847

12 Exelon has a long-term purchase contract to purchase capacity and energy from the Tenaska/Frontier unit, which is interconnected to both Entergy and ERCOT. As a result, the 853 MW of capacity from this unit is included both in Exelon's ERCOT and its Entergy market capacity number.

13 Because the 853 MW capacity of the Tenaska/Frontier unit is shown in both the ERCOT and Entergy markets, 853 MW has been removed from the total to prevent double-counting the Tenaska/Frontier capacity.

As this table shows, Exelon and NRG have overlapping generation in only four markets, and two of these four markets – the New England ISO and Entergy markets – involve only a *de minimis* overlap where the combined company will control less than 10% of the total installed capacity in the market. Thus, although Dr. Hieronymus analyzes all four of these markets, on its face only two markets could be significantly affected by the Transaction. This limited overlap is graphically illustrated by the map showing the location of Exelon's and NRG's generation, which is provided in Exhibit K.

In addition to the above markets, Dr. Hieronymus also conducted an analysis of the CSW market, which is the closest jurisdictional market to ERCOT where Exelon controls a modest amount of generation. Again, however, the amount of generation controlled by Exelon in the CSW market in the first place is very small, and on its face it is unlikely that the Transaction would raise problems in the CSW market – a fact that Dr. Hieronymus' analysis confirms as described below.

Furthermore, as described in greater detail below, Exelon is proposing a "clean sweep" divestiture in each market (or submarket) where there is any significant overlap of generation. In each of these markets, all of the generation owned by either Exelon or NRG will be divested. As a result, by definition the Transaction will not increase the level of concentration in any of these markets, except for the potential import of capacity into those markets. As Dr. Hieronymus demonstrates, the proposed clean sweep divestitures will adequately mitigate any potential adverse horizontal market power impacts from the Transaction.

Once he performed his initial screen to determine the markets where Exelon's and NRG's generation overlaps, Dr. Hieronymus performed an "Appendix A" analysis[14] of the Transaction as required by the Commission's Merger Regulations in each market where there is an overlap. As Dr. Hieronymus explains in detail in Sections III and IV of Exhibit J-1, this analysis requires the determination of pre and post Transaction market shares in each market analyzed, from which a Herfindahl-Hirschman Index ("HHI") can be derived. As Dr. Hieronymus explains, to the extent that the increase in HHI is above 100 in a moderately concentrated market (HHI from 1000 to 1800) or above 50 in a highly concentrated market (HHI above 1800), then that is considered by the Commission to be a "screen violation" that requires further analysis and potential mitigation. To the extent that HHI increases are lower than the levels described above, or if the post-Transaction HHI is unconcentrated (HHI below 1000), then there are no screen violations and no competitive issues raised.

Dr. Hieronymus' analysis of each market is summarized below.

1. PJM

PJM, with over 165,000 MW of capacity, operates the largest centralized electric pool in the United States. Within PJM prices can separate for significant numbers of hours during the year due to internal transmission constraints. Thus, when considering market power issues in PJM, the Commission typically analyzes smaller submarkets within PJM as well as PJM as a whole. *See Market-Based Rates Fro Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, FERC Stats. &

[14] The Appendix A analysis was first described in the Merger Policy Statement, III FERC Stats. & Regs. ¶ 31,044 at 30,130-135. The requirements of the Appendix A analysis since have been incorporated into the Commission's regulations (the "Merger Regulations") at 18 CFR § 33.3 (2004).

Regs. ¶ 31,352 at P 246 (2007). Therefore, Dr. Hieronymus analyzed the following PJM markets:

(a) PJM as a whole.

(b) "PJM East," which consists of New Jersey, the Delmarva Peninsula, and eastern Pennsylvania. Historically, transmission constraints between PJM East and the rest of PJM have caused market prices in PJM East to separate and rise above prices in the rest of PJM. Although recent transmission expansion projects have relieved these transmission constraints to some degree, the Commission still typically evaluates PJM East as a separate market.

(c) "PJM Classic", which consists of the footprint of the original PJM utilities, including PJM East. Dr. Hieronymus explains that, although he believes that a larger market than PJM Classic can be justified, he has analyzed this market because it is the smallest market that includes all of Exelon's and NRG's PJM capacity that is not located in Illinois. Because NRG and Exelon both own generation assets located in Pennsylvania that are outside of PJM East, use of this market thus provides the most conservative possible evaluation of the combination of the non-Illinois PJM generation assets of Exelon and NRG.

(d) Northern Illinois is not a separate relevant market *per se*, but Dr. Hieronymus presents facts to support the conclusion that the combination of Exelon's and NRG's generation in Northern Illinois does not have an adverse competitive effect.

For PJM East, Dr. Hieronymus conducts a Delivered Price Test ("DPT") analysis of (1) Economic Capacity and (2) Available Economic Capacity. For PJM and PJM Classic, Dr. Hieronymus analyzes Economic Capacity. He also analyzes relevant Ancillary Services markets in PJM.

Dr. Hieronymus' analysis of PJM focuses primarily on the Economic Capacity analysis. In PJM, where most states have implemented retail competition, Available Economic Capacity – which measures capacity available after load obligations are met – becomes less relevant.[15] Dr. Hieronymus' analysis of PJM and each PJM sub market is summarized below.

(a) PJM as a Whole

The ownership of capacity in the PJM market is relatively unconcentrated. As a result, even though Exelon's pre-merger market shares in the PJM market as a whole range from about 14%-16%, the addition of NRG's generation, which represents no more than 1% of the market, does not cause any screen violations. The results of Dr. Hieronymus' Economic Capacity analysis of the PJM market, which is included in Exhibit J-7, is reproduced below.

Economic Capacity, PJM (pre-mitigation)

		Pre-Merger						Post-Merger (Pre-Mitigation)			
		Exelon		NRG							
Period	Price	MW	Mkt Share	MW	Mkt Share	Market Size	HHI	MW	Mkt Share	HHI	HHI Chg
S_SP1	$250	23,961	14.5%	1,604	1.0%	165,368	790	25,565	15.5%	818	28
S_SP2	$160	23,197	14.4%	1,602	1.0%	161,314	798	24,799	15.4%	827	29
S_P	$ 90	21,669	14.3%	1,413	0.9%	151,602	817	23,082	15.2%	843	27
S_OP	$ 50	18,051	15.7%	999	0.9%	114,772	1,009	19,050	16.6%	1,036	27
W_SP	$105	21,460	14.1%	1,327	0.9%	151,769	765	22,788	15.0%	790	25
W_P	$ 75	18,841	14.2%	1,283	1.0%	132,677	811	20,124	15.2%	839	27
W_OP	$ 50	16,608	15.5%	896	0.8%	107,527	908	17,504	16.3%	933	26
SH_SP	$100	19,774	14.7%	1,227	0.9%	134,551	820	21,002	15.6%	847	27
SH_P	$ 70	15,903	14.5%	1,211	1.1%	109,931	905	17,114	15.6%	937	32
SH_OP	$ 45	15,463	17.4%	854	1.0%	88,781	1,062	16,317	18.4%	1,095	34

15 Moreover, it becomes very difficult to measure load obligations of third parties who have divested their generation to an entity (whether or not affiliated) that makes all of its sales in the wholesale market, and in particular it is difficult to match specific generation units to specific loads. Dr. Hieronymus explains the method that he has used to estimate Available Economic Capacity, but these calculations by their very nature represent an estimate that does not have the same degree of precision as the Economic Capacity calculations. *See* Exhibit J-1 at 50-51.

As this table shows, even after the combination of Exelon and NRG, the PJM Economic Capacity market is unconcentrated under most load conditions, and even though it becomes moderately concentrated in the Shoulder Off-Peak period, the HHI increase in this time period is 34 points, which is well be the 100 threshold used by the Commission for screening purposes. Order No. 642, FERC Stats. & Regs. ¶ 31,111 at 31,896 n. 62.

The same is true for the impact of the Transaction on Ancillary Services markets in PJM as a whole. As Dr. Hieronymus explains, the Transaction does not have any adverse impact on these markets in PJM as a whole. Exhibit J at 55-60.

(b) PJM East

The PJM East submarket is the market where the Transaction is most likely to raise competition issues. Exelon's pre-merger Economic Capacity market shares in PJM East range from about 17%-23%, while NRG's market shares are between 2% and 4%. The results of Dr. Hieronymus' Economic Capacity analysis of the PJM East market, also included in Exhibit J-7, is reproduced below:

Economic Capacity, PJM East (pre-mitigation)

		Pre-Merger						Post-Merger (Pre-Mitigation)			
		Exelon		NRG							
Period	Price	MW	Mkt Share	MW	Mkt Share	Market Size	HHI	MW	Mkt Share	HHI	HHI Chg
S_SP1	$250	9,296	20.8%	1,116	2.5%	44,711	1,088	10,411	23.3%	1,192	104
S_SP2	$200	9,298	20.8%	1,116	2.5%	44,647	1,090	10,414	23.3%	1,194	104
S_P	$100	7,065	18.5%	948	2.5%	38,131	955	8,012	21.0%	1,047	92
S_OP	$ 60	6,033	18.7%	910	2.8%	32,273	930	6,944	21.5%	1,036	105
W_SP	$120	7,908	20.2%	845	2.2%	39,067	1,012	8,753	22.4%	1,099	88
W_P	$ 90	6,573	18.3%	834	2.3%	35,856	940	7,407	20.7%	1,025	85
W_OP	$ 65	5,554	17.9%	811	2.6%	31,029	883	6,365	20.5%	977	94
SH_SP	$110	7,716	20.5%	823	2.2%	37,578	975	8,539	22.7%	1,064	90
SH_P	$ 80	5,908	17.6%	813	2.4%	33,513	880	6,721	20.1%	965	86
SH_OP	$ 55	5,522	19.1%	803	2.8%	28,924	867	6,326	21.9%	973	106

This table shows that, after the Transaction, the PJM East Economic Capacity markets are at most moderately concentrated under all load conditions and there are HHI increases of over 100 points in 4 of the load conditions analyzed. Although these screen violations are minor, Exelon nevertheless commits to mitigate any concern by implementing a clean sweep of the PJM East market, which it would accomplish by divesting all of the NRG generation facilities located in PJM East. Specifically, Exelon will divest the Indian River (784 MW), Vienna (170 MW) and Dover Energy (104 MW) facilities. In total, this equals approximately 1,000 MW of divestiture in PJM East. The terms and conditions of this proposed divestiture are described in more detail in Section V.B. below.

Dr. Hieronymus has calculated the impact of the Transaction in the PJM East market after this divestiture. This analysis is based on the simplifying assumption that the divested units will all be sold to a single new entrant. As discussed below, the Commission will be able to assess the impact of the divestiture based on the actual purchaser(s) when Exelon files for approval of the sales in the future. Because of the clean sweep, the only change in concentration resulting from the Transaction results from imports of NRG's generation into PJM East from other markets. Not surprisingly, as the following table, reproduced from Exhibit J-8, shows, this increase is *de minimis*, and no screen failures result after the divestiture.

Economic Capacity, PJM East (post-mitigation)

		Pre-Merger						Post-Merger (Pre-Mitigation)			
		Exelon		NRG							
Period	**Price**	**MW**	**Mkt Share**	**MW**	**Mkt Share**	**Market Size**	**HHI**	**MW**	**Mkt Share**	**HHI**	**HHI Chg**
S_SP1	$250	9,296	20.8%	1,116	2.5%	44,711	1,088	9,403	21.0%	1,097	9
S_SP2	$200	9,298	20.8%	1,116	2.5%	44,647	1,090	9,406	21.1%	1,099	9
S_P	$100	7,065	18.5%	948	2.5%	38,131	955	7,165	18.8%	963	8
S_OP	$ 60	6,033	18.7%	910	2.8%	32,273	930	6,097	18.9%	937	7
W_SP	$120	7,908	20.2%	845	2.2%	39,067	1,012	8,001	20.5%	1,021	9
W_P	$ 90	6,573	18.3%	834	2.3%	35,856	940	6,655	18.6%	948	8
W_OP	$ 65	5,554	17.9%	811	2.6%	31,029	883	5,613	18.1%	889	6
SH_SP	$110	7,716	20.5%	823	2.2%	37,578	975	7,821	20.8%	986	11
SH_P	$ 80	5,908	17.6%	813	2.4%	33,513	880	6,003	17.9%	889	9
SH_OP	$ 55	5,522	19.1%	803	2.8%	28,924	867	5,608	19.4%	877	10

Dr. Hieronymus' analysis of the PJM East Available Economic Capacity and Ancillary Services markets reaches similar conclusions. After the clean sweep divestiture of all of NRG's assets in PJM East, there are no competitive concerns raised by the Transaction for these products. *See* Exhibit J-1 at 52-53.

(c) PJM Classic

Exelon and NRG both own generation in Pennsylvania that is located outside of PJM East. Accordingly, Dr. Hieronymus determined that it was appropriate to conduct an analysis of a geographic market that includes this additional Pennsylvania generation, but which is smaller than the entire PJM market. Exhibit J-1 at 41-42. In order to derive a conservative geographic market that includes all of the PJM East and Pennsylvania generation but otherwise is as small as possible, Dr. Hieronymus determined to base his analysis on a PJM Classic market that includes all of the original PJM members. *Id*.

Dr. Hieronymus' analysis shows that, even in the conservatively small PJM Classic geographic market, the Transaction does not cause any competition concerns. As the following table, reproduced from Exhibit J-7, shows, the post-merger PJM Classic Market is unconcentrated in all load periods even before divestiture, and the HHI increases range from 36 to 45. Thus, the screen is passed in all periods. Order No. 642, FERC Stats. & Regs. ¶ 31,111 at 31,896 n. 62.

Economic Capacity, PJM Classic (pre-mitigation)

		Pre-Merger						Post-Merger (Pre-Mitigation)			
		Exelon		NRG							
Period	Price	MW	Mkt Share	MW	Mkt Share	Market Size	HHI	MW	Mkt Share	HHI	HHI Chg
S_SP1	$250	11,094	13.6%	1,349	1.7%	81,473	807	12,443	15.3%	852	45
S_SP2	$200	11,094	13.6%	1,350	1.7%	81,345	808	12,444	15.3%	853	45
S_P	$100	8,804	12.3%	1,176	1.7%	71,449	775	9,980	14.0%	816	41
S_OP	$ 55	7,699	13.0%	1,053	1.8%	59,093	803	8,752	14.8%	850	46
W_SP	$115	9,454	13.4%	1,041	1.5%	70,806	788	10,495	14.8%	827	39
W_P	$ 85	7,911	12.4%	928	1.5%	63,759	781	8,839	13.9%	818	36
W_OP	$ 60	6,987	12.4%	922	1.6%	56,289	788	7,908	14.1%	828	41
SH_SP	$105	8,987	13.6%	1,006	1.5%	66,322	776	9,994	15.1%	817	41
SH_P	$ 80	7,101	12.2%	897	1.5%	58,365	767	7,998	13.7%	804	37
SH_OP	$ 55	6,719	13.0%	904	1.8%	51,694	756	7,623	14.8%	801	45

(d) Northern Illinois Market

The only effect of the Transaction in Illinois relates to the combination of generation Exelon owns or contracts for in Illinois (about 13,000 MW, of which about 1,600 MW consists of peakers) with NRG's Rockford peaking station (448 MW). Thus, the impact of the Transaction, if any, only occurs when peaking units are economic, and thus the Rockford peaking station would ordinarily be dispatched, which is not often. As Dr. Hieronymus testifies, peakers in Northern Illinois had an annual capacity factor of only about 2 percent. Exhibit J-1 at 54. Dr. Hieronymus demonstrates that there is about 4,000 MW of similar vintage peaking capacity owned by unaffiliated third parties in the Illinois portion of PJM, and that, on average, there was more than 3,500 MW of competing generation operating in this region when some portion of the Rockford station was operating. Based on these facts, he concludes that there is no adverse effect from the Transaction in Northern Illinois. *Id*.

2. ERCOT

The second geographic market where there is a significant amount of overlap of generation ownership is within the ERCOT region. The transmission and wholesale sale of electricity in ERCOT is not in interstate commerce and thus is not subject to the Commission's jurisdiction, and it therefore is not clear whether the Commission considers the impact of Transactions on competition in ERCOT as part of its Section 203 public interest review. In the past, the Commission has ruled on transactions that include assets located in ERCOT without indicating whether or not it has considered the impact of the transaction on competition in ERCOT. *See*, *e.g.*, *Oncor Electric Delivery Company*, 120 FERC ¶ 61,215 (2007); *NRG Energy, Inc.*, 113 FERC ¶ 62,245 (2005).

To the extent that the Commission does consider competitive impacts in ERCOT, however, it is clear that the Transaction will not adversely impact competition in ERCOT. Exelon is committing, as part of this Application, to conduct a clean sweep divestiture by divesting all of Exelon's generation located in ERCOT. In particular, Exelon will divest the Mountain Creek, Handley and Laporte units[16] that it owns in ERCOT and will, in addition, transfer the long-term power purchase agreement ("PPA") rights that it has to the capacity and energy associated with the Tenaska/Frontier and Wolf Hollow units.[17] In total, this will result in the divestiture of approximately 2,200 MW of capacity and the transfer of long-term contract rights for an additional approximately 1,200 MW of capacity. The terms and conditions of these divestitures are described below.

16 This includes the sale of the mothballed Mountain Creek Units 2-3 and Handley Units 1-2.

17 Exelon will either assign its rights and obligations to a third party, or in the event that it cannot obtain the necessary consents from the project owner to do so or cannot find an entity willing to take an assignment, may enter into a back-to-back power purchase agreement with a counterparty that will give that counterparty the same rights that Exelon has to the capacity and energy from the unit. In the latter case, Exelon contractually will stand between the plant owner and the counterparty to the back-to-back power purchase agreement, but all of Exelon's control over the output of the unit will have been contractually transferred to the counterparty, and Exelon will have no ability to withhold the capacity from the market, either operationally or economically by setting a high price for the sale of the units' output.

With this clean sweep divestiture, there can be no real question but that the Transaction will have no adverse impact on competition in ERCOT. Nevertheless, because of the theoretical possibility of imports from other markets, Dr. Hieronymus has performed an analysis of the overall ERCOT market, as well as two of the four congestion zones within the ERCOT market, (i) Houston; and (ii) North, the two zones where Exelon and NRG's pre-merger generation ownership overlaps. Dr. Hieronymus limited his analysis to Economic Capacity because ERCOT has implemented retail competition and as a consequence no market participant has any native load obligations.

(a) ERCOT

Dr. Hieronymus determined that the ERCOT market as a whole is unconcentrated in all load periods, both before and after the Transaction, as shown on the following table taken from Exhibit J-10.

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Economic Capacity, ERCOT (pre-mitigation)

		Pre-Merger						Post-Merger (Pre-Mitigation)			
		Exelon		NRG							
Period	Price	MW	Mkt Share	MW	Mkt Share	Market Size	HHI	MW	Mkt Share	HHI	HHI Chg
S_SP1	$250	2,995	3.8%	12,502	15.9%	78,427	847	15,497	19.8%	969	122
S_SP2	$130	2,995	3.8%	12,502	16.0%	78,404	847	15,497	19.8%	969	122
S_P	$ 75	2,750	3.7%	11,720	15.9%	73,801	865	14,470	19.6%	983	118
S_OP	$ 65	1,118	1.9%	9,231	15.5%	59,386	790	10,349	17.4%	848	59
W_SP	$ 90	2,964	3.8%	11,932	15.5%	77,085	822	14,896	19.3%	941	119
W_P	$ 60	1,114	2.2%	5,285	10.2%	51,724	700	6,399	12.4%	744	44
W_OP	$ 55	1,114	2.2%	5,285	10.3%	51,367	696	6,399	12.5%	741	45
SH_SP	$100	2,803	4.0%	10,858	15.3%	70,873	807	13,661	19.3%	928	121
SH_P	$ 70	1,505	2.4%	9,600	15.2%	63,171	827	11,105	17.6%	900	72
SH_OP	$ 50	1,072	2.6%	4,208	10.1%	41,734	758	5,279	12.7%	809	52

As this table shows, the ERCOT market is unconcentrated even before the clean sweep divestiture. As a result, the Transaction passes the competitive screens and raises no competition issues in the ERCOT market as a whole, even though there are some modest increases in concentration.

(b) ERCOT North Zone

All but one of Exelon's generation facilities are located in the North Zone, as is NRG's Limestone plant with a capacity of almost 1,700 MW. As a result, the combination of the two companies causes six relatively small screen violations in ERCOT North, as shown in the following table, taken from Exhibit J-10.

Economic Capacity, North Zone (pre-mitigation)

		Pre-Merger						Post-Merger (Pre-Mitigation)			
		Exelon		NRG							
Period	Price	MW	Mkt Share	MW	Mkt Share	Market Size	HHI	MW	Mkt Share	HHI	HHI Chg
S_SP1	$250	2,878	8.4%	3,123	9.1%	34,370	1,762	6,001	17.5%	1,914	152
S_SP2	$130	2,878	8.4%	3,123	9.1%	34,347	1,760	6,001	17.5%	1,912	152
S_P	$ 75	2,750	8.3%	3,162	9.6%	32,971	1,757	5,912	17.9%	1,916	160
S_OP	$ 65	1,118	4.2%	2,941	11.0%	26,837	1,495	4,059	15.1%	1,586	91
W_SP	$ 90	2,842	8.4%	2,932	8.7%	33,705	1,660	5,774	17.1%	1,807	147
W_P	$ 60	1,114	4.4%	2,243	8.9%	25,104	1,236	3,357	13.4%	1,315	79
W_OP	$ 55	1,114	4.4%	2,244	8.9%	25,104	1,229	3,358	13.4%	1,308	79
SH_SP	$100	2,697	8.6%	2,790	8.9%	31,382	1,618	5,487	17.5%	1,771	153
SH_P	$ 70	1,505	5.4%	2,775	9.9%	28,087	1,635	4,280	15.2%	1,741	106
SH_OP	$ 50	1,072	4.7%	2,151	9.4%	22,945	1,236	3,222	14.0%	1,324	88

However, these screen violations are completely eliminated by the clean sweep divestiture. As Dr. Hieronymus testifies, because the interties into ERCOT are completely reserved by parties other than Exelon or NRG, the clean sweep divestiture completely eliminates the HHI increases that result from the Transaction under his simplifying assumption that the divested units are sold to a purchaser with no pre-Transaction market presence. Exhibit J-1 at 65-67. Again, the Commission will be able to evaluate the impact of selling to a specific purchaser(s) when Exelon files for approval of the sales.

(c) ERCOT Houston Zone

Although Exelon has only a single peaking facility in the Houston Zone, NRG has over 8,000 MW of capacity in this zone. As a result, the Transaction causes five relatively modest screen violations in the peak load periods when Exelon's generation would be expected to run, as the following table taken from Exhibit J-10 shows.

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Economic Capacity, Houston Zone (pre-mitigation)

		Pre-Merger						Post-Merger (Pre-Mitigation)			
		Exelon		NRG							
Period	Price	MW	Mkt Share	MW	Mkt Share	Market Size	HHI	MW	Mkt Share	HHI	HHI Chg
S_SP1	$250	483	1.8%	10,193	38.9%	26,202	1,875	10,676	40.8%	2,018	143
S_SP2	$130	483	1.8%	10,193	38.9%	26,202	1,875	10,676	40.8%	2,018	143
S_P	$ 75	349	1.5%	9,426	39.4%	23,932	1,977	9,776	40.9%	2,092	115
S_OP	$ 65	184	0.9%	7,034	33.1%	21,262	1,639	7,217	33.9%	1,696	57
W_SP	$ 90	519	1.9%	9,905	35.8%	27,711	1,667	10,424	37.6%	1,801	134
W_P	$ 60	217	1.1%	3,429	17.9%	19,200	1,138	3,646	19.0%	1,178	40
W_OP	$ 55	217	1.1%	3,431	17.9%	19,200	1,140	3,649	19.0%	1,180	40
SH_SP	$100	504	2.0%	9,012	36.0%	25,037	1,668	9,516	38.0%	1,813	145
SH_P	$ 70	243	1.1%	7,792	35.0%	22,249	1,696	8,035	36.1%	1,773	76
SH_OP	$ 50	228	1.6%	2,541	18.2%	13,993	1,193	2,769	19.8%	1,252	59

Again, these screen violations are completely eliminated by the clean sweep divestiture under the assumption that the divested units are sold to a purchaser with no pre-Transaction market presence. Exhibit J-1 at 65-67.

3. CSW

Exelon, but not NRG, controls generation in the CSW market. Because CSW has interconnections with ERCOT and is the closest jurisdictional market to ERCOT, Dr. Hieronymus performed an Appendix A analysis of the CSW market to see if the potential for increased imports of NRG capacity from ERCOT into CSW somehow could create competitive concerns in the CSW market. Because there is no retail competition in CSW, Dr. Hieronymus conducted both an Economic Capacity and an Available Economic Capacity analysis in this market.

The Economic Capacity analysis for CSW is presented below, taken from Exhibit J-11. As this analysis shows, although the Economic Capacity market is highly concentrated, the market is almost completely unaffected by the Transaction. At most, there is an HHI increase of 3, even before taking the clean sweep divestiture into consideration. Thus, there are no Economic Capacity screen violations in the CSW market. Order No. 642, FERC Stats. & Regs. ¶ 31,111 at 31,896 n. 62.

Economic Capacity, CSW

		Pre-Merger						Post-Merger (Pre-Mitigation)			
		Exelon		NRG							
Period	Price	MW	Mkt Share	MW	Mkt Share	Market Size	HHI	MW	Mkt Share	HHI	HHI Chg
S_SP1	$250	521	3.8%	15	0.1%	13,557	4,517	536	4.0%	4,517	1
S_SP2	$130	521	3.9%	15	0.1%	13,528	4,517	536	4.0%	4,518	1
S_P	$ 80	521	4.0%	15	0.1%	13,153	4,410	536	4.1%	4,411	1
S_OP	$ 50	522	5.9%	20	0.2%	8,848	2,930	542	6.1%	2,933	3
W_SP	$ 90	514	3.8%	24	0.2%	13,392	4,053	539	4.0%	4,054	1
W_P	$ 65	516	4.3%	24	0.2%	12,018	3,707	541	4.5%	3,709	2
W_OP	$ 40	2	0.0%	43	1.0%	4,357	5,484	45	1.0%	5,484	—
SH_SP	$ 90	484	3.9%	28	0.2%	12,497	3,976	513	4.1%	3,978	2
SH_P	$ 70	487	4.1%	32	0.3%	11,886	3,860	519	4.4%	3,862	2
SH_OP	$ 40	2	0.1%	57	1.4%	4,221	4,891	59	1.4%	4,891	—

Dr. Hieronymus' Available Economic Capacity analysis of the CSW market, also taken from Exhibit J-11, is shown below. This analysis shows that, although the HHI increases are larger than they are for the Economic Capacity analysis, there still are no screen violations. The largest increase of 80 points occurs during the Winter Off-Peak period, which is an unconcentrated market, and thus there is no screen violation. In those load conditions where the market is highly concentrated, the highest HHI increase is 30 points, well below the 50-point threshold for highly concentrated markets. Order No. 642, FERC Stats. & Regs. ¶ 31,111 at 31,896 n. 62.

Available Economic Capacity, CSW

		Pre-Merger						Post-Merger (Pre-Mitigation)			
		Exelon		NRG							
Period	Price	MW	Mkt Share	MW	Mkt Share	Market Size	HHI	MW	Mkt Share	HHI	HHI Chg
S_SP1	$250	540	12.9%	17	0.4%	4,186	2,869	556	13.3%	2,879	10
S_SP2	$130	536	12.8%	16	0.4%	4,186	2,862	552	13.2%	2,871	10
S_P	$ 80	535	9.1%	15	0.3%	5,889	2,275	549	9.3%	2,279	5
S_OP	$ 50	533	12.8%	48	1.2%	4,153	2,809	582	14.0%	2,839	30
W_SP	$ 90	530	8.6%	22	0.4%	6,185	2,064	552	8.9%	2,070	6
W_P	$ 65	546	8.8%	28	0.5%	6,227	2,060	574	9.2%	2,068	8
W_OP	$ 40	14	1.7%	204	23.8%	857	892	218	25.5%	972	80
SH_SP	$ 90	513	10.2%	40	0.8%	5,050	1,960	553	11.0%	1,976	16
SH_P	$ 70	517	8.1%	29	0.5%	6,378	2,069	547	8.6%	2,077	7
SH_OP	$ 40	17	1.7%	209	20.8%	1,005	795	226	22.5%	866	71

4. Entergy

Both Exelon and NRG also own or control generation in the Entergy market. However, Exelon's generation consists solely of its long-term PPA for the capacity and energy associated with the Tenaska Frontier Unit, which can sell power either into ERCOT or into Entergy. As explained above, Exelon is committing to transfer its rights under this contract to a third party as part of its clean sweep of ERCOT. Exelon's ERCOT-related commitment with respect to the Tenaska Frontier Unit will eliminate any overlap in the Entergy market as well.

5. ISO New England

There is some minor overlap of generation in the ISO New England ("ISO-NE") market. However, Exelon owns only 178 MW of capacity, which is about 0.6% of the total installed capacity in ISO-NE, while NRG's 2,404 MW constitutes only a little over 7% of the installed capacity in ISO-NE. Moreover, Exelon's and NRG's generation is located in different sub-areas within ISO-NE. As Dr. Hieronymus explains, this is a *de minimis* overlap of generation that, under Section 33.2(a)(2)(i) of the Commission's regulations, does not require the preparation of an Appendix A analysis. Exhibit J at 69-70.

B. Proposed Generation Divestiture

1. Timing of Divestiture

As noted above, Exelon has committed to divest 4,600 of generating capacity, by selling three NRG plants with a capacity of approximately 1,000 MW in PJM East and three Exelon plants with a capacity of approximately 2,200 MW in ERCOT, and by transferring to third parties Exelon's long-term tolling PPA rights to approximately 1,200 MW of capacity located in ERCOT. Exelon commits that it will enter into contracts to sell its generation capacity and to transfer its long-term contract rights no later than 180 days after the consummation of the Transaction. Exelon will then close on the sales and transfers no later than 30 days after the receipt of all regulatory approvals, including the receipt of this Commission's approval under Section 203 of the Federal Power Act.

2. Identity of Purchasers

Dr. Hieronymus modeled the divestitures as having been made to a single purchaser in both the PJM East and ERCOT markets, and in both cases his analysis assumed that the purchaser has no pre-existing market presence, which was a simplifying assumption used for illustrative purposes. Exelon recognizes that the identity of the purchaser(s) of the divested generation could have an impact on the post-divestiture concentration in the markets where the divestitures take place. However, given that Exelon cannot sell the generation to be divested until it receives the Commission's approval to do so, Exelon does not believe that it is appropriate to make any commitments now about which purchaser(s) could purchase which units. The Commission will have the ability to consider any competition issues raised by the identity of the purchaser(s) when it conducts its Section 203 review of the specific divestitures that Exelon will be required to file at the time of the sales.

3. Interim Mitigation

In the past, the Commission has required that merger applicants put interim mitigation measures in place from the time of the consummation of the merger until the required divestitures or other mitigation is in place. *See*, *e.g. AEP*, 91 FERC ¶ 61,208 (2000); *Ameren Services Co.*, 101 FERC ¶ 61,202 (2002); *Ameren Corp.*, 108 FERC ¶ 61,094 (2004). Exelon therefore commits to implement interim mitigation provisions that will go into effect upon the consummation of the Transaction, as described below.

As an initial matter, however, Exelon notes that it is much more difficult for market power to be exercised in large organized markets than it might have been when the Commission first began requiring interim mitigation. These markets have independent market monitors with detailed information about all market participants' costs and offers, which enable them to detect when a party might be attempting to affect prices through the exercise of market power, and who also can rely on tools memorialized in their RTOs' FERC-filed tariffs and agreements to mitigate the exercise of market power. For this reason, the Commission adopted "a rebuttable presumption" that the existing Commission-approved RTO/ISO mitigation is sufficient to address market power concerns with respect to market-based rate authority in the RTO/ISO market, including mitigation applicable to RTO/ISO submarkets. *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, (Order No. 697-A), FERC Stats. & Regs. ¶ 31,268 at P 285 (2008).

The generation facilities that Exelon is proposing to divest here are located either in PJM or ERCOT, two of the largest competitive electric markets in the United States.

Each has a sophisticated and active independent market monitor that undoubtedly would be able to detect any attempts by Exelon to manipulate market prices in the interim before divestiture. As a result, and given the relatively modest competitive overlaps in these markets, there should be no market power concerns with respect to the short period of time before the divestitures are completed. Nevertheless, because the Commission never has applied the rebuttable presumption in Order No. 697-A to mitigation in Section 203 proceedings, Exelon is proposing additional interim mitigation measures to ensure that no market power issues are raised as a result of the Transaction. Because the markets in PJM and ERCOT operate somewhat differently, the proposed interim mitigation in each market also is different.

(a) Interim Mitigation in PJM East

Exelon's interim mitigation will apply, with limited exceptions, to all of the fossil-fired and hydro units owned or controlled by Exelon and NRG (the "PJM East Mitigated Units") that are located in PJM East.[18] A list of the PJM East Mitigated Units is attached to this Application as Appendix 1. The interim mitigation will apply to sales of energy, capacity, and ancillary services from the PJM East Mitigated Units, and will be in effect from the time that the Transaction is consummated until the date that the last NRG unit located in PJM East is transferred to a new owner (the "PJM East Interim Mitigation Period").

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18 Three fossil-fired generation units located in PJM East are not being designated as PJM East Mitigation Units. First, the diesel-fired peakers located at Cromby and Schuylkill are not PJM Capacity Resources. These peakers are available to PJM only as Black Start resources. Accordingly, these units will not be offered into the PJM energy market and have not been designated as PJM East Mitigation Units. In addition, although Exelon does submit offers for the output of the Grays Ferry cogeneration unit, Exelon does not own the unit and does not have any contractual right to shut down the unit or reduce its output. Because Exelon cannot withhold the output of Grays Ferry from the market, Exelon is not including it as a PJM East Mitigation Unit.

Energy Mitigation

During the PJM Interim Mitigation Period, all PJM East Mitigated Units, including both Exelon and NRG units, will be subject to cost-based caps – equal to the "Cost-Based Offer" defined below – on the offers that are made for the PJM East Mitigated Units into the PJM Energy market. These are "up to" offer caps, meaning that Exelon will be permitted to submit offers lower than the offer caps or to must-run a unit with an offer price of zero for all or a portion of a unit's capability. A "Cost-Based Offer" means an offer to sell energy at the maximum price allowed under the version of the PJM "Amended and Restated Operating Agreement of PJM Interconnection, LLC," (the "PJM Operating Agreement"), Schedule 1, Section 6.4.2(a)ii and iii, available at www.pjm.com, in effect at the time the offer is made. Currently, this limits offers to the variable cost of a unit plus an adder, where variable cost is defined and recorded in PJM's Cost Development Task Force "CDTF" rules, PJM Manual 15, and where the adder for each unit is dependent on whether or not PJM has classified the unit as a frequently mitigated unit ("FMU"). Normally, this means a 10% adder for non-FMU units, and a fixed percentage and/or a fixed $/MWH adder for FMUs. An offer to must-run a unit or a portion of a unit at zero price also will constitute a Cost-Based Offer.[19]

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19 The Muddy Run pumped storage hydro unit cannot be offered into the market at all times. The first reason is that its dispatch is constrained as a function of PJM's management and operation of the Conowingo Dam, which PJM schedules. In addition, there are obligations contained in Exelon's FERC license for the Conowingo Dam governing water elevation levels, which also constrain Muddy Run scheduling, as well as NRC operating procedures that require sufficient water levels to enable the Peach Bottom nuclear facility to maintain operations. Exelon does commit, however, that it will bid in the Muddy Run unit as a must-run unit with a zero price offer at those times when it does offer and schedule the units into the energy market. In addition, the dispatch of Exelon's Conowingo hydro station is controlled by the PJM system operator, not Exelon. Exelon therefore commits to schedule the output from this unit dispatched by PJM as must-run with a zero price offer.

Capacity Mitigation

The interim mitigation will apply to all of the RPM Base Residual Auctions (as that term is defined by PJM), if any, that take place during the PJM Interim Mitigation Period. For all such auctions, Exelon will offer all of the units listed in Appendix 1 up to their PJM-approved Market Seller Offer Caps as defined in Section 6 of the PJM Open Access Tariff. Exelon may sell the capacity associated with any of these units that do not clear in any of these RPM Base Residual Auctions on a bilateral basis. With respect to any RPM Incremental Auction (as that term is defined by the PJM Operating Agreement) for additional capacity needed during the delivery period associated with a Base Residual Auction conducted during the PJM East Mitigation Period, Exelon will offer, at prices up to their PJM-approved Market Seller Offer Caps, all units that have: (1) not cleared in prior Base Residual Auctions; (2) not been used to cover any deficiencies in capacity sold in the Base Residual Auction; and (3) not been sold bilaterally to third parties before the upcoming Incremental Auction.

Ancillary Services Mitigation

In PJM, there are only two market-based ancillary services – regulation and synchronized reserves. Dr. Hieronymus explains why the Transaction does not adversely affect these markets even without any mitigation. Exhibit J-1 at 57-60. As a result, there should be no need for any interim mitigation for these ancillary services.

Nevertheless, for the avoidance of doubt, Exelon commits that to the extent that it offers ancillary services into these ancillary service markets during the PJM Interim Mitigation Period from any unit, not just the PJM East Mitigated Units, Exelon's offers will be consistent with the rules set out in PJM's Manual regarding cost-based bidding, PJM Manual 15 – Cost Development Guidelines (the "CDTF Manual").

With respect to regulation service, Section 9 of the CDTF Manual sets out a methodology for calculating the cost-based bid that a party must submit when offering regulation service to PJM. The rules are the same as they are for energy, meaning that they allow Exelon to make a market-based bid as well. Exelon will commit to cap any offer to sell regulation service from PJM East Mitigated Units at a price no greater than cost-based offer as determined in accordance with Section 9 of the CDTF Manual and will not avail itself of the market-based option. With respect to synchronized reserves, Section 7 of the CDTF Manual sets out a methodology for calculating a cost-based offer. That methodology includes a prescribed adder. Exelon will commit to cap its offers to sell synchronized reserves from PJM East Mitigated Units a price up to the value calculated in accordance with Section 7 of the CDTF Manual.

(b) Interim Mitigation in ERCOT

Exelon's interim mitigation will apply to fossil-fired units owned or controlled by Exelon and NRG (the "ERCOT Mitigated Units") that are located in the ERCOT North and Houston Zones. A list of the ERCOT Mitigated Units is attached to this Application as Appendix 2. This mitigation will remain in effect from the time that the Transaction is consummated until the date that the last sale of an Exelon unit located in ERCOT that it will divest has closed (the "ERCOT Interim Mitigation Period").

Because the current ERCOT market operates very differently than the PJM market, Exelon's commitments relating to the ERCOT market are different from its commitments with respect to the PJM market. In ERCOT, Qualified Scheduling Entities ("QSEs") submit balanced schedules on behalf of generators on a day-ahead basis, meaning that the generation scheduled is matched to energy sales that generators have made bilaterally. To the extent the result of these submissions for a particular generator is such that the generator is committed to operate but has excess capacity, the generator may participate in the ancillary services markets that ERCOT administers. The ERCOT ancillary services are Regulation Up, Regulation Down, Responsive Reserve Service, Non-Spinning Reserve Service, and Balancing Energy Service either Up or Down (referred to as "Balancing Energy"). Generators are not required to make offers for the first four of these services and can also provide these bilaterally. If generators do submit such offers, however, to the extent their offers clear, their resources are committed to ERCOT to provide such service(s) on a firm basis for the next day.

Exelon cannot physically withhold capacity from the ERCOT market by choosing not to enter into bilateral contracts or not bidding into the ERCOT bid-based markets. On both a day-ahead basis and in real time, ERCOT can issue an Out-of-Merit Capacity ("OOMC") instruction to a unit that is not on-line when ERCOT needs the capacity to relieve congestion or remedy extreme emergency conditions. When ERCOT does this, it pays the owner of the OOMC resource a generic, cost-based amount equal to a generic heat rate by unit type multiplied by a gas index multiplied by the low operating limit of the resource multiplied by the number of hours for which the unit must be available for

OOMC operation.[20] Similarly, with respect to units that are already on-line, if ERCOT needs energy from a particular resource to enable it to relieve a local transmission constraint or other local reliability issue, it can issue an Out-of-Merit Energy ("OOME") instruction calling for upward or downward movement from a specific unit to solve the constraint. ERCOT pays a generator subject to an OOME instruction a price equal to a generic heat rate by unit type multiplied by the applicable gas index multiplied by the MW amount associated with the OOME instruction or if its costs exceed the generic payment, a generator may seek its verifiable costs from ERCOT.

As a result, Exelon's interim mitigation proposal relates to energy associated with the capacity that is available from generating units that have been committed day-ahead after being dispatched to meet bilateral contract obligations. ERCOT clears the markets for the four ancillary services other than Balancing Energy on an ERCOT-wide basis. As described above, the ERCOT-wide market does not experience any screen failures as a result of the Transaction, even before divestiture. As a result, there is no need for interim mitigation with respect to any of these ancillary services.

ERCOT clears the Balancing Energy market, however, on a zonal basis unless there is no congestion on ERCOT-designated Commercially Significant Constraints. As a result, Exelon will offer all energy from committed units not needed to serve bilateral contracts or to supply the other ancillary services into the Balancing Energy market that will not exceed the unit's applicable resource category generic costs for OOME service for upward instruction as set forth in the ERCOT Protocols, Section 6 Ancillary Services.

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20 If a generator's unit has an actual heat rate that is higher than the generic heat rate, the generator may submit its verifiable cost information to ERCOT and request that it be paid based on the higher, actual heat rate.

(c) The Proposed Interim Mitigation Should Be Accepted

Exelon's proposed interim mitigation should be accepted by the Commission. The proposed offer caps for both ERCOT and PJM efficiently implement the twin goals of preventing both physical withholding and economic withholding during the interim period before divestiture is completed. First, there is no possibility of physical withholding in PJM East because all of the PJM East Mitigated Units are required to be offered into the market, as explained above, while ERCOT dispatchers have the right t to require any unit not committed to be dispatched and any unit not running at fully capacity to be ramped up. Second, the offer caps require all energy that is offered into the market (other than energy scheduled in ERCOT for bilateral transactions that by definition are economic) to be offered at cost-based prices, as defined by the relevant market rules for purposes other than to implement this proposal. Thus, the offer caps will prevent Exelon submitting offers at uncompetitive levels that would result in economic withholding.

There is an additional feature of Exelon's proposal that makes it superior to all previous interim mitigation proposals approved by the Commission. In every other proposal, the amount of capacity subject to interim mitigation has been equal to the amount of capacity ultimately being divested. Exelon, however, is proposing to place its offer caps on considerably more capacity than is being divested. In PJM East, Exelon is proposing to apply the offer caps on over 4,000 MW of fossil, hydro and biomass generation even though only about 1,000 MW of capacity is being divested. The generation covered by the offer cap includes the so-called "ability generation" that can set the market clearing price in PJM East and hypothetically could be withheld from the market to increase prices. In ERCOT, the offer caps apply to *all* generation owned by either Exelon or NRG in the North and Houston Zones, even though only the Exelon capacity will be divested. These offer caps thus should more than adequately mitigate market power during the Interim Mitigation Period. *See* Exhibit J-1 at 9-13.

(d) Alternative Interim Mitigation Proposal for ERCOT

As explained in the testimony of Dr. Hieronymus and above, Exelon's interim mitigation proposal fully addresses any market power concerns that may arise in ERCOT during the ERCOT Interim Mitigation Period. Exelon recognizes, however, that while its proposal imposes offer caps that eliminate the potential for economic withholding in the zonal balancing energy markets, the proposal depends on ERCOT to address any potential physical withholding in these zonal balancing energy markets through the issuance of OOMC and OOME instructions. It would not be economic to require Exelon to make offers into the Balancing Energy market for all ERCOT Mitigated Units because this would require uneconomic units to be operated at minimum levels in order to be able to deliver balancing energy even though it is unlikely that the unit's bid actually would be accepted. Given the remote potential for physical withholding to affect the balancing energy markets and the ability of ERCOT to issue OOMC and OOME instructions, Exelon believes that its interim mitigation proposal is sufficient.

To the extent, however, that the Commission determines that the proposed interim mitigation does not effectively mitigate merger-related changes in the combined company's market power in the ERCOT markets and the Commission finds it necessary to order additional interim mitigation in ERCOT, Exelon proposes an alternative interim mitigation plan for the Commission's consideration. This alternative would involve commitments with respect to the generation assets located in ERCOT that currently are owned by Exelon (the "Exelon ERCOT Assets"), which are listed on Appendix 2. In particular, under this alternative, Exelon would commit as follows with respect to the Exelon ERCOT Assets:

(i) Control over the bidding and scheduling, as well as control over all other QSE services for the Mountain Creek and Handley units would be transferred to an independent third party during the ERCOT Interim Mitigation Period. That is, Exelon no longer would be the QSE for the units at these two facilities during the ERCOT Interim Mitigation Period. There are a number of entities that provide QSE services for generation owners in ERCOT, and therefore it will not be difficult to obtain such services for this purpose. The typical compensation paid to QSEs for such services is a fixed fee per MWH generated, which would not give any financial incentive to bid or dispatch the units in such a fashion as to benefit Exelon's other generation assets. To the extent that Exelon pays additional compensation, that compensation will be based solely on the QSE's performance with respect to the assets that it controls, which again will provide no incentive to benefit Exelon's other generation.

(ii) Complex contractual arrangements associated with the Tenaska/Frontier, Wolf Hollow and LaPorte units would make it extremely difficult to transfer dispatch and bidding control of these units to a third party. Therefore, Exelon proposes to retain bidding control over those resources, but will commit during the ERCOT Interim Mitigation Period to bid into the balancing energy market any amount of the capacity that is not scheduled in the day ahead market or otherwise sold bilaterally, up to the full amount of the capacity of each of these units, except for 300 MW of the Tenaska/Frontier capacity that is subject to a pre-existing long-term sales contract for sales to Entergy.[21] These bids will be at the same ERCOT-established generic cost-based prices described above. This commitment applies to every hour of the ERCOT Interim Mitigation Period, except to the extent that a unit is down for scheduled or unscheduled maintenance.[22] As a result, the entire capacity of each of these units will be made available to the market in every hour that they are capable of operating for the full length of the ERCOT Interim Mitigation Period.

These commitments should easily address any lingering market power concerns – particularly given the additional ability of ERCOT to issue OOMC and OOME instructions. In the ERCOT North Zone, the above commitments will apply to all assets except for NRG's Limestone coal-fired unit, which is a baseload unit particularly unsuited to the execution of a withholding strategy. Exelon would have very little incentive to operate the Limestone unit so as to benefit the Exelon assets, given that the variable operating costs of Limestone are significantly lower than the variable operating costs of the Exelon resources in the North Zone. At the same time the above proposed commitments will prevent the Exelon ERCOT Assets located in the North Zone from

21 As explained above, the Tenaska/Frontier Unit is capable of making sales in either the ERCOT or Entergy markets. Exelon currently has a long-term sales contract to sell 300 MW of capacity to Entergy through May of 2010. Exelon will satisfy this obligation through two of the three 150 MW gas turbines in the unit. The other gas turbine, plus the steam turbine will be subject to this commitment to the extent available, consistent with Exelon's contractual obligations to Entergy.

22 The Tenaska/Frontier and Wolf Hollow Units are not owned by Exelon, and Exelon has no control over any unforced outages that may require unscheduled maintenance. The Laporte Unit is operated by Air Products, and thus Exelon again has no control over forced outages that require unscheduled maintenance. Exelon does have the ability to suggest dates for the scheduled maintenance forall three facilities, but all planned outages must be submitted to, and approved by, ERCOT.

being withheld in order to benefit the Limestone unit. Similarly, the only Exelon asset in the Houston Zone – the only other Zone where competitive issues are raised – is the LaPorte unit, which is a high-cost peaker. Exelon would have little incentive to operate the NRG assets located in the Houston Zone to benefit the LaPorte unit, and the commitment would prevent the LaPorte Unit from being withheld to benefit the NRG units in the Houston Zone.

Again, Exelon believes that its primary interim mitigation plan for ERCOT fully and efficiently mitigates any merger-related ability or incentive that Exelon might acquire as a result of the Transaction. As a result, this alternative proposal need not be required. Exelon strongly prefers its primary interim mitigation plan because it is less complicated and less costly to implement.

4. No Potential for Abuse of Natural Gas Transportation Market Power

The Commission's Merger Policy and Merger Regulations also address the issue of the potential abuse of market power in the transportation of natural gas to gain a competitive advantage in energy markets. The concern is that when the ownership of natural gas assets serving electric generation facilities is combined with the ownership of electric generation facilities, the potential is created for the resulting merged company to use its control over the natural gas facilities to disadvantage the competing owners of the electric generation facilities. Order No. 642, FERC Stats. & Regs.¶ 31,111 at 31,904.[23]

[23] The regulations governing vertical market power appear at Section 33.4 of the Merger Regulations.

Here, neither Exelon nor NRG owns any natural gas transmission facilities. PECO does own natural gas distribution facilities and there are a number of independent natural gas-fired generation facilities in PECO's gas service territory. However, as Dr. Hieronymus explains, only a few generation facilities are served by PECO, and this minor amount of capacity served is unlikely to create vertical market power issues. Exhibit J-1 at 73. Moreover, PECO is obligated to provide open-access natural gas distribution service that is subject to continued regulation by the PAPUC. Under these circumstances, no vertical market power issues are raised by PECO's ownership of natural gas distribution facilities, particularly given that Exelon has committed to sell all of NRG's generation located in PJM East, where the PECO gas distribution system is located.

Finally, Dr. Hieronymus considered whether there could be any vertical market power issues raised by the combination of the natural gas transportation contract rights of Exelon and NRG, an issue that is not implicated by the Commission's merger regulations but which had been considered in the proposed merger of Exelon and PSEG. As Dr. Hieronymus observes, the Commission found that the Exelon/PSEG merger would not have raised vertical market power concerns with respect to their transportation contracts, and NRG has a significantly smaller share of transportation contracts than PSEG did. Exhibit J-1 at 73. Moreover, any contract rights that NRG has will be transferred to the purchaser of its generation facilities in PJM East. As a result, no vertical market power issues are raised with respect to the combination of natural gas transportation contract rights.

C. <u>No Adverse Impact On Rates</u>

In considering the impacts of a merger on rates, the Commission looks primarily at impacts on transmission rates and on rates for long-term wholesale requirements customers. The Transaction will not have an adverse impact on either of these categories of rates.

1. Transmission Rates

With respect to transmission rates, Exelon proposes a "hold harmless" commitment, *i.e.* for a period of five years they will not seek to include merger-related costs in their filed transmission revenue requirements unless they can demonstrate merger-related savings equal to or in excess of the merger-related costs so included. The Commission has approved this type of commitment in its Merger Policy Statement and in a number of subsequent cases. Merger Policy Statement, FERC Stats. & Regs. ¶ 31,044 at 30,124; *see also Ameren Corp.*, 108 FERC ¶ 61,094 at P 6-8 (2004); *Great Plains Energy Incorporated*, 121 FERC ¶ 61,069 at P 48 (2007).

2. Wholesale Requirements Rates

Neither of the traditional franchised utilities involved in the Transaction has any wholesale requirements customers. Thus the Transaction can have no impact on any wholesale requirements rates and no commitments are required.

D. <u>No Adverse Impact On Regulation</u>

Although the Commission requires merger applicants to evaluate the effect of a proposed transaction on regulation, both at the federal and state level, the Commission indicated in Order No. 642 that it would not ordinarily set a merger application for hearing with respect to the impact on regulation unless: (a) the proposed transaction involves public utility subsidiaries of a registered holding company under the Public

Utility Holding Company Act of 1935 (“PUHCA 1935”) and the relevant applicants do not commit to abide by the Commission’s policies on pricing of non-power goods and services between affiliates, or (b) the affected state commissions lack authority over the proposed transaction and raise concerns about the effect on regulation. Order No. 642, FERC Stats. & Regs. ¶ 31,111 at 31,914-15. Neither of these concerns is raised by this Application.

The first prong of the test in the Merger Policy Statement no longer is applicable since the repeal of PUHCA 1935. Moreover, Exelon’s and NRG’s public utility subsidiaries will each remain as a jurisdictional public utility subject to regulation by the Commission after the Transaction closes to the same extent each was regulated before the closing of the Transaction. As a result, there will be no impact on the Commission’s jurisdiction.

Nor does the Transaction have any impact on state regulation. Pennsylvania and Illinois will have the same jurisdiction over PECO and ComEd after the Transaction that they have today. No other state public utility commission with jurisdiction over any other Exelon or NRG entity will have its jurisdiction affected in any respect.

E. No Improper Cross-Subsidization

Under the amendments to Section 203 implemented by the Energy Policy Act of 2005, the Commission “shall approve” a proposed transaction “if it finds that the proposed transaction . . . will not result in cross-subsidization of a non-utility associate company or the pledge or encumbrance of utility assets for the benefit of an associate company, unless . . . the cross-subsidization, pledge, or encumbrance will be consistent with the public interest.” FPA § 203(a)(4).

In Order Nos. 669, 669-A and 669-B, the Commission identified a four-factor test that applicants must satisfy in order to address the concerns identified in Section 203 regarding any possible cross-subsidization, pledge or encumbrance of utility assets associated with the proposed transaction. Under this test, the Commission examines whether a proposed transaction, at the time of the transaction or in the future, results in:

(1) transfers of facilities between a traditional utility associate company with wholesale or retail customers served under cost-based regulation and an associate company;

(2) new issuances of securities by traditional utility associate companies with wholesale or retail customers served under cost-based regulation for the benefit of an associate company;

(3) new pledges or encumbrances of assets of a traditional utility associate company with wholesale or retail customers served under cost-based regulation for the benefit of an associate company;

(4) new affiliate contracts between non-utility associate companies and traditional utility associate companies with wholesale or retail customers served under cost-based regulation, other than non-power goods and services agreements subject to review under Sections 205 and 206 of the FPA.

Order No. 669 at P 169, FERC Stats. & Regs. ¶ 31,200; Order No. 669-A, FERC Stats. & Regs. ¶ 31,214 at P 144. Exhibit M hereto contains a verification, based on facts and circumstances known to Exelon or that are reasonably foreseeable, that the Transaction will not result in any of the above-outlined transfers of facilities, issuances or securities, pledges or encumbrance of assets or other agreements. Exhibit M also contains, as required by 18 CFR § 33.2(i), the existing pledges and encumbrances of the regulated utilities, ComEd and PECO (the “Regulated Companies”).

As an additional measure of protection to ensure that the Transaction cannot result in any inappropriate cross subsidization of non-utility businesses by captive utility customers, Exelon is offering a comprehensive package of ring-fencing measures by which they commit to be bound upon closing of the Transaction. Exelon recognizes that the Transaction will expand the scope of Exelon's operations in competitive power businesses. Consequently, Exelon has decided to take appropriate steps to ensure that the Regulated Companies and their customers will not be affected adversely by the business cycles and risks that accompany competitive power businesses. The below-outlined ring-fencing measures go well beyond normal practices and ensure that the Transaction will not result in any change to the operations of the Regulated Companies.

Attached is an affidavit of Susan D. Abbott, an expert in utility credit ratings. Ms. Abbott worked for 20 years for Moody's Investors Services where, as Managing Director, she was responsible for the ratings of public electric and combination utilities, and project finance deals. Ms. Abbott has examined Exelon's ring-fencing commitments (set forth below) and concludes that they go beyond what the rating agencies (Moody's and Standard & Poor's) look for to consider a utility effectively "ring-fenced" from its parent and non-utility affiliates. In reaching this conclusion, Ms. Abbott explains Moody's very specific ring-fencing conditions and Standard & Poor's more general ring-fencing guidelines, and compares Exelon's commitments to the rating agencies' conditions for achieving effective ring-fencing.

Further, Ms. Abbott discusses the ring-fencing measures that protected Portland General Electric Company from Enron's bankruptcy and concludes that Exelon's commitments compare favorably to the Portland General measures. The Portland General ring-fencing measures are proven because neither Portland General's customers nor its bondholders suffered the effects of Enron's demise and bankruptcy, and Portland General was able to maintain a 9 credit rating notch difference above Enron. Given the favorable comparison of Exelon's commitments to Portland General's measures, Ms.

Abbott is comfortable that Exelon's proposed provisions will ring-fence ComEd and PECO effectively. Ms. Abbott believes that Exelon's commitments satisfy the conditions of the rating agencies, and will provide an even stronger foundation for protection of ComEd and PECO from parent or affiliate financial difficulties than was in place for Portland General.

Ring-Fencing Commitments

The following ring-fencing commitments encompass both existing business practices and new procedures, and upon consummation of the Transaction these practices and procedures will become binding commitments that can be counted on by regulators as well as rating agencies and utility creditors. These ring-fencing commitments include the following:

Corporate Governance. The Regulated Companies each will maintain its own Board of Directors, separate from the Exelon board and the board of any other Exelon affiliate, with at least one independent director on each Regulated Company's board who is not an officer or director of Exelon or any other Exelon affiliate.[24]

Duties of the Boards of Directors. Under the laws of Illinois and Pennsylvania respectively, the business and affairs of the Regulated Companies will be managed by or under the direction of their respective boards of directors who shall manage the business and affairs of the Regulated Companies consistent with their unique obligations as public utilities and in accordance with the directors' fiduciary duties.

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[24] For purposes of the following commitments, references to Exelon affiliates shall not, in the case of ComEd, include subsidiaries of ComEd, and shall not, in the case of PECO, include subsidiaries of PECO.

Board Action. Unless otherwise provided in a Regulated Company's certificate or articles of incorporation or bylaws, the act of the majority of the directors present at a meeting at which a quorum is present shall be the act of the Board of Directors; provided that any action by a Regulated Company's Board of Directors to authorize the following acts shall require the affirmative vote of a majority of that company's directors present at the meeting at which a quorum is present, which affirmative vote shall include the vote of at least one independent director:

a) seeking protection or relief under federal or state bankruptcy, insolvency, moratorium or similar law affecting the rights of creditors;

b) the declaration and payment of dividends on its common stock; and

c) the purchase of electric energy or capacity or ancillary services unless undertaken pursuant to an auction, competitive bidding or similar process authorized by state law or managed or supervised by state authority.

Maintenance of Capital Structure. ComEd and PECO each will issue its own long-term debt and use reasonable efforts to maintain separate credit ratings for its publicly traded securities. Exelon has not guaranteed and will not guarantee any of the debt or other securities of the Regulated Companies or indemnify any person for losses resulting therefrom. Each Regulated Company will use its reasonable best efforts and exercise management prudence in matters relating to dividends and capital investments in order to preserve an investment grade credit rating.

Cost of Capital of Regulated Distribution Operations. The cost of capital advocated by each Regulated Company for use in establishing its retail and wholesale rates shall not reflect any risk adjustment associated with Exelon or any other Exelon affiliate. For purposes of this commitment, cost of capital shall include the respective cost of debt, preferred stock and common equity as applied to the Regulated Company's individual capital structure.

Investment Conditions. Without prior regulatory approval from either the ICC or the PAPUC as appropriate, neither ComEd nor PECO shall:

a) guarantee the debt or credit instruments of Exelon or any other Exelon affiliate;

b) grant a mortgage or other lien on any property used and useful in providing retail or wholesale utility service or otherwise pledge such assets as security for repayment of the principal or interest of any loan or credit instrument of Exelon or any other Exelon affiliate;

c) include in any of ComEd’s or PECO’s debt or credit agreements cross default provisions between their respective securities and the securities of Exelon or any other Exelon affiliate;

d) include in ComEd’s or PECO’s debt or credit agreements any financial covenants or rating agency triggers related to Exelon or any other Exelon affiliate.

Intercompany Borrowings. Neither ComEd nor PECO will lend money to, or borrow money from, Exelon or any other Exelon affiliate except pursuant to “money pool” arrangements filed with FERC.[25]

Transactions Between Regulated Companies and Exelon Affiliates. ComEd and PECO will each maintain reasonable accounting controls and other procedures for the allocation of overhead and other costs of jointly used assets and personnel. Such controls and procedures will be designed to provide reasonable assurance that neither ComEd nor PECO, as applicable, bears costs associated with the business activities of any other Exelon affiliate other than the reasonable costs of providing materials and services to ComEd or PECO, as the case may be. ComEd and PECO also will each maintain reasonable pricing protocols for determining transfer prices for transactions involving non-power goods and services between itself and any other Exelon affiliate consistent with the requirements of the ICC and the PAPUC, respectively, and the FERC.

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25 Any money pool agreement will be filed for informational purposes in Docket No. RM02-14. 18 CFR § 141.500; *see also* Order No. 634-A, *Regulation of Cash Mgmt. Practices*, Order No. 634-A, FERC Stats. & Regs. ¶ 31,152 at P 39 (2003) (implementing reporting requirements for regulated entities that participate in cash management programs; requiring regulated entities “file their cash management agreements with the Commission, and [ ] file any subsequent changes within 10 days from the date of change.”)

Books and Records. ComEd and PECO will each maintain its own separate books and records. Upon written request, Exelon will provide to the ICC, PAPUC and the FERC reasonable access to the books, accounts and other records of other Exelon affiliates to the extent: (a) such books, accounts and other records are relevant to the costs incurred by the Regulated Companies for purchases of goods and services from Exelon affiliates; or (b) access to such books, accounts and other records is necessary or appropriate for the protection of customers of the Regulated Companies with respect to rates subject, respectively, to the ICC, the PAPUC or FERC jurisdiction. However, nothing set forth herein shall constitute or be interpreted as a waiver by Exelon or the Regulated Companies of their right to raise traditional discovery objections to any such requests, including, but not limited to, objections on the basis of relevance and privilege. Additionally, before responding to any such requests, Exelon or the Regulated Companies shall be permitted to require the imposition of protections to prohibit disclosure of proprietary or confidential information.

Notification of Certain Payments and Transfer of Funds. ComEd and PECO will notify the ICC and the PAPUC, respectively, of (a) its intention to declare dividends on common stock at least 30 days before such a dividend is paid; and (b) its most recent quarterly common stock cash dividend within two business days after the declaration of such dividend.

Ownership and Transfer of Assets. ComEd and PECO each will maintain ownership in its own name or the name of its subsidiaries all assets and other interests in property (including leasehold interests, easements, licenses, beneficial interests, and jointly owned assets) used or useful in its transmission and distribution businesses and will not transfer its ownership of any such property to any other Exelon affiliate without the requisite approval of or notification to the ICC and the PAPUC, respectively, and any requisite approval under the Federal Power Act.

Non-Consolidation Opinion. Within 90 days of closing the Transaction, ComEd and PECO each will deliver to the ICC, the PAPUC, respectively, and the FERC an opinion of counsel that, in the event of a bankruptcy or liquidation of Exelon, then ComEd or PECO, as the case may be, will not be consolidated with or into the estate of Exelon and, in the event of a bankruptcy or liquidation of ComEd or PECO, as the case may be, then Exelon will not be consolidated with or into the estate of ComEd or PECO, as applicable.

Implementation of the above-outlined commitments, which can be changed only with Commission approval, will ring-fence ComEd and PECO from Exelon and other affiliates, thereby foreclosing the potential for cross-subsidization resulting from the Transaction. With these commitments, the Transaction readily meets the requirements of Section 203(a)(4).

F. The Internal Reorganization is Consistent with the Public Interest

As noted in Section III.C above, Exelon anticipates that there will be some internal reorganization of the combined company’s corporate structure that cannot be precisely determined at this time in light of the opposition of NRG’s management. This reorganization would involve consolidating the various companies owned by Exelon and NRG into a structure that makes more sense for the combined company.

Any such reorganization will be consistent with the requirements for blanket authorization under Section 33.1(c)(6) of the Commission's regulations. There will be no reorganization of either PECO or ComEd, which are the only traditional public utilities owned by either Exelon or NRG. Nor will that part of the holding company structure that includes PECO and ComEd be revised in any fashion, *i.e.* there will be no changes from Exelon Energy Delivery Company LLC and below, as shown on the organization chart attached as Exhibit C. Furthermore, the reorganization will not raise any cross-subsidization issues other than the ones raised by the Transaction in general, which are described above. Exelon therefore believes that the internal reorganization qualifies for the blanket authorization under Section 33.1(c)(6) and will not require the Commission's specific authorization in this proceeding. To the extent that the Commission disagrees, Exelon requests that the Commission authorize this reorganization as part of its authorization of the Transaction. Such authorization would be conditioned upon compliance with the commitment that neither PECO nor ComEd would be included in the reorganization.

VI. INFORMATION REQUIRED BY PART 33 OF THE COMMISSION'S REGULATIONS

Exelon submits the following information pursuant to Part 33 of the Commission's Regulations.

A. Section 33.2(a): Names and addresses of the principal business offices of the applicants.

1. Exelon's principal executive offices are located at 10 South Dearborn Street, Chicago, Illinois 60603.
2. NRG's principal business offices are locatred at 211 Carnegie Center, Princeton, NJ 08540-6213

B. Section 33.2(b): Names and addresses of persons authorized to receive notices and communications in respect to the Application.

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C. Section 33.2(c): Description of Applicants.

See Section II, and Exhibits A through F, attached.

D. Section 33.2(d): Description of the jurisdictional facilities owned, operated or controlled by Applicants, their parents or affiliates.

See Section II and the testimony of Dr. Hieronymus.

E. Section 33.2(e): Narrative description of the Transaction.

A narrative description of the Transaction is provided in Part III of this Application.

F. Section 33.2(f): Contracts with respect to the Transaction.

See Exhibit I.

G. Section 33.2(g): Facts relied upon to show that the Transaction is in the public interest.

The facts relied upon to show that the Transaction is consistent with the public interest are set forth in Part V of this Application and in the testimony of Dr. Hieronymus, attached as Exhibit J.

H. Section 33.2(h): Physical property.

See Exhibit K.

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I. Section 33.2(i): Status of actions before other regulatory bodies.

See Exhibit L.

J. Section 33.5: Accounting Entries

The only two entities owned by Exelon or NRG that are required to maintain their books in accordance with the Uniform System of Accounts are PECO and ComEd. Exelon does not intend to reflect any aspect of the Transaction on the books of either PECO or ComEd, and therefore there are no pro forma accounting entries to provide.

VII. CONCLUSION

As demonstrated above, as well as in the attached testimony and exhibits, the Transaction is consistent with the public interest as defined by the Commission in its Merger Policy Statement, Part 33 regulations, and merger cases. Exelon requests that the Commission approve the Transaction, without a hearing, no later than May 1, 2009.

Respectfully submitted,

/s/ Mike Naeve

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Counsel for
Exelon Corporation

December 18, 2008

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Exelon Corporation **)** **Docket No. EC09-______**

VERIFICATION

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District of Columbia)
) ss.
City of Washington)

NOW, BEFORE ME, the undersigned authority, personally came and appeared, Elizabeth A. Moler, who, after first being duly sworn by me, did say:

That she is Executive Vice President of Exelon Corporation; that she has the authority to verify the foregoing application and exhibits on behalf of Exelon Corporation**]**; that she has knowledge of the matters therein; and that to the best of her knowledge, information and belief, the representations made are true and correct.

____
Elizabeth A. Moler

SUBSCRIBED AND SWORN to before me this ____ day of ___________ 2008.

____
Notary Public

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Appendix 1 –PJM East Mitigated Units

Exelon PJM East Mitigated Units

Sub Market	Unit Name	Unit Type
East	Chester 7-9	Peaker
East	Cromby 1,2	Coal/Oil
East	Croydon	Peaker
East	Delaware 9-12, D1	Peaker
East	Eddystone 1-4	Coal/Oil/NG
East	Eddystone 10-40	Peakers
East	Fairless Hills A,B	LFG/NG
East	Falls 1-3	Peakers
East	Montenay	Biomass Steam
East	Moser 1-3	Peakers
East	Muddy Run 1-8	Pumped Storage
East	Pennsbury	LFG
East	Richmond 91, 92	Peakers
East	Schuylkill 1	Oil
East	Schuylkill 10,11	Peakers
East	Conowingo 1-11	Hydro
East	Southwark 3-6	Peaker

NRG PJM East Mitigated Units

Sub Market	Unit Name	Unit Type
East	Indian River	Coal/Oil
East	Dover	NG/Coal
East	Vienna	Oil

Appendix 2 —*ERCOT Mitigated Units*

Exelon ERCOT Mitigated Units

Unit Name	Region	Capacity (MW)
Handley 3	ERCOTN	395MW
Handley 4, 5	ERCOTN	870MW
Mountain Creek 6, 7	ERCOTN	240MW
Mountain Creek 8	ERCOTN	565MW
LaPorte	ERCOTH	152MW
Wolf Hollow (PPA)	ETCOTN	350MW
Frontier (PPA)	SERC (Entergy- Texas)	830MW

NRG ERCOT Mitigated Units

Unit Name	Region	Capacity (MW)
WA Parish –coal	ERCOTH	2,460MW
Limestone – coal	ERCOTN	1,690MW
Cedar Bayou	ERCOTH	1,500MW
TH Wharton	ERCOTH	1,025MW
WA Parish	ERCOTH	1,190MW
SR Bertron	ERCOTH	840MW
Greens Bayou	ERCOTH	760MW
San Jacinto	ERCOTH	165MW

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Appendix 3

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Exelon Corporation	**)**	**Docket No. EC09-______**

PROPOSED
PROTECTIVE ORDER

1. This Protective Order shall govern the use of all Protected Materials produced, by, or on behalf of, any Participant. Notwithstanding any order terminating this proceeding, this Protective Order shall remain in effect until specifically modified or terminated by the Presiding Administrative Law Judge (“Presiding Judge”) or the Federal Energy Regulatory Commission (“Commission”).

2. A Participant may designate as protected those materials which customarily are treated by that Participant as sensitive or proprietary, which are not available to the public, and which, if disclosed freely, would subject that Participant or its customers to risk of competitive disadvantage or other business injury. A Participant may also designate as protected those materials that should be treated as Critical Energy Infrastructure Information subject to protection under Sections 388.112 and 388.113 of the Commission’s regulations.

3. Definitions — For purposes of this Order:

(a) The term “Participant” shall mean a Participant as defined in 18 C.F.R. § 385.102(b).

(b) (1) The term “Protected Materials” means (A) materials (including depositions) provided by a Participant in response to discovery requests and designated by such participant as protected; (B) any information contained in or obtained from such materials; (C) any other materials which are made subject to this Protective Order by the Presiding Judge, by the Commission, by any court or other body having appropriate authority, or by agreement of the Participants; (D) notes of Protected Materials; and (E) copies of Protected Materials. The Participant producing the Protected Materials shall physically mark them on each page as “PROTECTED MATERIALS’ or with words of similar import as long as the term “ Protected Materials” is included in that designation to indicate that they are Protected Materials.

(2) The term “Notes of Protected Materials” means memoranda, handwritten notes, or any other form of information (including electronic form) which copies or discloses materials described in Paragraph 3(b)(l). Notes of Protected Materials are subject to the same restrictions provided in this order for Protected Materials except as specifically provided in this order.

(3) Protected Materials shall not include (A) any information or document contained in the files of the Commission, or any other federal or state agency, or any federal or state court, unless the information or document has been determined to be protected by such agency or court, or (B) information that is public knowledge, or which becomes public knowledge, other than through disclosure in violation of this Protective Order.

(c) The term "Non-Disclosure Certificate" shall mean the certificate annexed hereto by which Participants who have been granted access to Protected Materials shall certify their understanding that such access to Protected Materials is provided pursuant to the terms and restrictions of this Protective Order, and that such Participants have read the Protective Order and agree to be bound by it. All Non-Disclosure Certificates shall be served on all parties on the official service list maintained by the Secretary in this proceeding.

(d) The term "Reviewing Representative" shall mean a person who has signed a Non-Disclosure Certificate and who is:

(1) Commission Litigation Staff;

(2) an attorney who has made an appearance in this proceeding for a Participant;

(3) attorneys, paralegals, and other employees associated for purposes of this case with an attorney described in (2);

(4) an expert or an employee of an expert retained by a Participant for the purpose of advising, preparing for or testifying in this proceeding;

(5) person designated as a Reviewing Representative by order of the Presiding Judge or the Commission; or

(6) employees or other representatives of Participants appearing in this proceeding with significant responsibility for this docket.

4. Protected Materials shall be made available under the terms of this Protective Order only to Participants and only through their Reviewing Representatives as provided in Paragraphs 7, 8, and 9.

5. Protected Materials shall remain available to Participants until the later of the date that an order terminating this proceeding becomes no longer subject to judicial review, or the date that any other Commission proceeding relating to the Protected Material is concluded and no longer subject to judicial review. If requested to do so in writing after that date, the Participants shall, within fifteen days of such request, return the Protected Materials (excluding Notes of Protected Materials) to the Participant that produced them, or shall destroy the materials, except that copies of filings, official transcripts and exhibits in this proceeding that

contain Protected Materials, and Notes of Protected Material may be retained, if they are maintained in accordance with Paragraph 6, below. Within such time period each Participant, if requested to do so, shall also submit to the producing Participant an affidavit stating that, to the best of its knowledge, all Protected Materials and all Notes of Protected Materials have been returned or have been destroyed or will be maintained in accordance with Paragraph 6. To the extent Protected Materials are not returned or destroyed, they shall remain subject to the Protective Order.

6. All Protected Materials shall be maintained by the Participant in a secure place. Access to those materials shall be limited to those Reviewing Representatives specifically authorized pursuant to Paragraphs 8 and 9. The Secretary shall place any Protected Materials filed with the Commission in a non-public file. By placing such documents in a non-public file, the Commission is not making a determination of any claim of privilege. The Commission retains the right to make determinations regarding any claim of privilege and the discretion to release information necessary to carry out its jurisdictional responsibilities.

For documents submitted to Commission Litigation Staff ("Staff"), Staff shall follow the notification procedures of 18 C.F.R. § 388.112 before making public any materials.

7. Protected Materials shall be treated as confidential by each Participant and by the Reviewing Representative in accordance with the certificate executed pursuant to Paragraph 9. Protected Materials shall not be used except as necessary for the conduct of this proceeding, nor shall they be disclosed in any manner to any person except a Reviewing Representative who is engaged in the conduct of this proceeding and who needs to know the information in order to carry out that person's responsibilities in this proceeding. Reviewing Representatives may make copies of Protected Materials, but such copies become Protected Materials. Reviewing Representatives may make notes of Protected Materials, which shall be treated as Notes of Protected Materials if they disclose the contents of Protected Materials.

8. (a) If a Reviewing Representative's scope of employment includes the marketing of energy, the direct supervision of any employee or employees whose duties include the marketing of energy, the provision of consulting services to any person whose duties include the marketing of energy, or the direct supervision of any employee or employees whose duties include the marketing of energy, such Reviewing Representative may not use information contained in any Protected Materials obtained in this proceeding to give any Participant or any competitor of any Participant a commercial advantage.

(b) In the event that a Participant wishes to designate as a Reviewing Representative a person not described in Paragraph 3(d) above, the Participant shall seek agreement from the Participant providing the Protected Materials. If an agreement is reached, that person shall be a Reviewing Representative pursuant to Paragraph 3(d) above with respect to those materials. If no agreement is reached, the Participant shall submit the disputed designation to the Presiding Judge for resolution.

(c) A Reviewing Representative shall not be permitted to inspect, participate in discussions regarding, or otherwise be permitted access to Protected Materials pursuant to this Protective Order unless that Reviewing Representative has first executed a Non-Disclosure Certificate provided that if an attorney qualified as a Reviewing Representative has executed such a certificate, the paralegals, secretarial and clerical personnel under the attorney's instruction, supervision or control need not do so. A copy of each Non-Disclosure Certificate shall be provided to counsel for the Participant asserting confidentiality prior to disclosure of any Protected Material to that Reviewing Representative.

9. Attorneys qualified as Reviewing Representatives are responsible for ensuring that persons under their supervision or control comply with this order.

10. Any Reviewing Representative may disclose Protected Materials to any other Reviewing Representative as long as the disclosing Reviewing Representative and the receiving Reviewing Representative both have executed a Non-Disclosure Certificate. In the event that any Reviewing Representative to whom the Protected Materials are disclosed ceases to be engaged in these proceedings, or is employed or retained for a position whose occupant is not qualified to be a Reviewing Representative under Paragraphs 3(d), access to Protected Materials by that person shall be terminated. Even if no longer engaged in this proceeding, every person who has executed a Non-Disclosure Certificate shall continue to be bound by the provisions of this Protective Order and the certification.

11. Subject to Paragraph 17, the Presiding Judge shall resolve any disputes arising under this Protective Order. Prior to presenting any dispute under this Protective Order to the Presiding Judge, the parties to the dispute shall use their best efforts to resolve it.

12. If a Participant tenders for filing any written testimony, exhibit, brief or other submission that includes, incorporates, or refers to Protected Materials, all portions thereof referring to such materials shall be filed and served in sealed envelopes or other appropriate containers endorsed to the effect that they are sealed pursuant to this Protective Order. Such documents shall be marked "PROTECTED MATERIALS" and shall be filed under seal and served under seal upon the Presiding Judge and all Reviewing Representatives who are on the service list. For anything filed under seal, redacted versions or, where an entire document is protected, a letter indicating such, will also be filed with the Commission and served on all parties on the service list and the Presiding Judge. Counsel for the producing Participant shall provide to all Participants who request the same, a list of Reviewing Representatives who are entitled to receive such material. Counsel shall take all reasonable precautions necessary to assure that Protected Materials are not distributed to unauthorized persons.

If any Participant desires to include, utilize or refer to any Protected Materials in such a manner that might require disclosure of such material, such Participant shall first notify both counsel for the producing Participant and the Presiding Judge of such desire, identifying with particularity each of the Protected Materials and the proposed manner of their use, and shall provide to both counsel for the producing Participant and the Presiding Judge, in a sealed envelope bearing the caption "PROTECTED MATERIALS" copies of the Protected Materials in the form they are intended to be used. Notification of the desire to use protected materials at trial without in camera restrictions shall be provided to counsel for the producing Participant not more than 10 calendar days prior to the date established for the oral argument to show cause. If the producing Participant is unwilling to waive objection to disclosure of such Protected Materials, the producing Participant shall provide to the Presiding Judge, not later that five days after the receipt of the Reviewing Participant's notification, affidavits[26] with respect to each of the identified Protected Materials demonstrating the reasons for maintaining the confidentiality of the Protected Materials, and a Master Index of the Protected Materials, and/or within the same time period the Participants shall file a trial stipulation waiving application of the Protective Order to the use at and after trial of Protected Material relative to adjudication of the stipulated issues, other than any Protected Materials applicable to Critical Energy Infrastructure information. The affidavit shall set forth facts delineating that the information designated as Protected Materials has been maintained in a confidential manner and the precise nature and justification for the monetary injury that would result from the disclosure of such information. The affidavit shall specify the name and corporate position of the person or persons supplying or preparing or assisting in the preparation of the information designated as Protected Materials and the name and corporate position of the person or persons to whom such information has been communicated. The producing Participant shall provide copies of the affidavits and Master Index of Protected Materials to each Reviewing Participant. Oral argument to show cause why such Protected Materials should remain protected shall be held in accordance with the procedural schedule in this proceeding. All objections and arguments related to the Protected Materials shall be conducted in camera, closed to all parties except the Reviewing Representatives as described in Paragraph 3(d), hereof. That portion of the hearing transcript which refers to such Protected Materials shall be sealed and subject to this Protective Order. All Protected Materials which ultimately may be admitted into evidence, shall be filed in sealed, confidential envelopes or other appropriate containers endorsed to the effect that they are sealed pursuant to this Protective Order.

13. Nothing in this Protective Order shall be construed as precluding any Participant from objecting to the use of Protected Materials on any legal grounds.

14. Nothing in this Protective Order shall preclude any Participant from requesting the Presiding Judge, the Commission, or any other body having appropriate authority, to find that this Protective Order should not apply to all or any materials previously designated as Protected Materials pursuant to this Protective Order. The Presiding Judge may alter or amend this Protective Order as circumstances warrant at any time during the course of this proceeding.

15. Each party governed by this Protective Order has the right to seek changes in it as appropriate from the Presiding Judge or the Commission.

16. All Protected Materials filed with the Commission, the Presiding Judge, or any other judicial or administrative body, in support of, or as a part of, a motion, other pleading, brief, or other document, shall be filed and served in sealed envelopes or other appropriate containers bearing prominent markings indicating that the contents include Protected Materials subject to this Protective Order.

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26 The affidavits shall comply with International Paper Company v. Fireboard Corp., 63 FRD 88, 93-94 (D. Del. 1974) and Parsons v. General Motors Corp., 85 FRD 724, 726 (N.D. Ga 1980), and, if claims of work-product are concerned, with Cajun Electric Power Coop., Inc. v. Gulf States Utilities Co., 43 FERC ¶ 63,012 at 65,129 (1988).

17. In the event that the Presiding Judge at any time in the course of this proceeding finds that all or part of the Protected Materials are not confidential, those materials nevertheless shall continue to be subject to the protection afforded by this Protective Order for three (3) business days from the date of issuance of the Presiding Judge's decision, and if the Participant seeking protection files an interlocutory appeal or requests that the issue be certified to the Commission, for an additional seven (7) business days. None of the Participants waives its rights to seek additional administrative or judicial remedies after the Presiding Judge's decision respecting Protected Materials or Reviewing Representatives, or the Commission's denial of any appeal thereof. The provisions of 18 C.F.R. § 388.112 shall apply to any requests for Protected Materials in the files of the Commission under the Freedom of Information Act. (5 USC § 552).

18. Nothing in this Protective Order shall be deemed to preclude any Participant from independently seeking through discovery in any other administrative or judicial proceeding information or materials produced in this proceeding under this Protective Order.

19. None of the Participants waives the right to pursue any other legal or equitable remedies that may be available in the event of actual or anticipated disclosure of Protected Materials.

20. The contents of Protected Materials or any other form of information that copies or discloses Protected Materials shall not be disclosed to anyone other than in accordance with this Protective Order and shall be used only in connection with this (these) proceeding(s). Any violation of this Protective Order and of any Non-Disclosure Certificate executed hereunder shall constitute a violation of an order of the Commission.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Exelon Corporation	**)**	**Docket No. EC09-______**

NON-DISCLOSURE CERTIFICATE

I hereby certify my understanding that access to Protected Materials is provided to me pursuant to the terms and restrictions of the Protective Order in this proceeding, that I have been given a copy of and have read the Protective Order, and that I agree to be bound by it. I understand that the contents of the Protected Materials, any notes or other memoranda, or any other form of information that copies or discloses Protected Materials shall not be disclosed to anyone other than in accordance with that Protective Order. I acknowledge that a violation of this certificate constitutes a violation of an order of the Federal Energy Regulatory Commission.

By: ______________________________

Title: ______________________________

Representing: ______________________________

Exhibit A: Business Activities of Applicants

The business activities of Exelon are further described in Part II of this Application and in the attached testimony.

Exhibit B: List of Energy Subsidiaries and Affiliates

EXELON

A list of Exelon's energy subsidiaries and affiliates is attached as Exhibit B.1.

NRG

A list of NRG's energy subsidiaries and affiliates is attached as Exhibit B.2. This list is taken from NRG's most recent Section 203 filing in Docket No. EC07-93-000. Exelon does not know if there have been any material changes to this list that have not been reported by NRG.

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Exhibit B-1 **Exelon Affiliates**:

(All companies are 100% owned directly or indirectly by Exelon Corporation)

All Energy Gas & Electric Marketing Co., LLC	Sells natural gas at retail to commercial and industrial customers.
AmerGen Energy Company, LLC	AmerGen owns and operates Three Mile Island Unit 1 located in Pennsylvania, the Clinton Power Station located in Illinois and the Oyster Creek Generating Station in New Jersey.
Commonwealth Edison Company	Provides retail electric services to customers in and around Chicago.
Commonwealth Edison Company of Indiana, Inc.	Principally engaged in the transmission of electricity which is sold to the ComEd service territory.
ENEH Services, LLC	Provide operations and maintenance services to affiliated electric generation facilities in New England.
Exelon AOG Holding #1, Inc.	Holding Company.
Exelon AOG Holding #2, Inc.	Holding Company.
Exelon Energy Company	Provides gas and electric service to commercial and industrial customers in Illinois, Ohio, Pennsylvania, and Michigan.
Exelon Framingham, LLC	Fossil fueled peaking plants (Framingham 1, 2 and 3), utilizing a combination of fuel oil and natural gas.
Exelon Generation Company, LLC	Owns Exelon's generating assets and coordinates the dispatch and sale of generation, and markets energy in the wholesale, bilateral and spot markets.
Exelon New Boston LLC	Fossil fueled peaking plant (20 MW).
Exelon New England Power Marketing, Limited Partnership	Power Marketer.
Exelon West Medway, LLC	Fossil fueled peaking plants (Medway 1, 2 and 3) utilizing a combination of fuel oil and natural gas.
Exelon Wyman	Fossil fueled peaking plant with 36 MW. Exelon owns a 5.88% proportionate interest in this facility (operated by Florida Power and Light.)
PECO Energy Company	Provides electric and gas services in southeastern Pennsylvania.

Exhibit B-1

PECO Energy Power Company	Owns 514 MW Conowingo Hydroelectric Project, a generating facility located on the Susquehanna River in Pennsylvania and Maryland. PEPCO owns Pennsylvania portion of the Conowingo project. The Maryland portion is owned by PEPCO’s subsidiary, Susquehanna Power Company.
Southeast Chicago Energy Project, LLC	Owns a peaking plant in Chicago, Illinois.
Susquehanna Electric Company	Leases and operates Conowingo project; sells bulk power to PECO Energy Company; does not serve the public.
Susquehanna Power Company	Owns Maryland part of Conowingo project. (See PECO Energy Power Company - 514 MW Conowingo Hydroelectric Project, a generating facility located on the Susquehanna River in Pennsylvania and Maryland. PEPCO owns Pennsylvania portion of the Conowingo project.)

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Exhibit B-2 NRG Energy Subsidiaries and Affiliates:

Subsidiary Name	Description	NRG
Arthur Kill Power LLC	Generator	100.00%
Astoria Gas Turbine Power LLC	Generator	100.00%
Bayou Cove Peaking Power, LLC	Generator	100.00%
Berrians I Gas Turbine Power LLC	Generation project development company	100.00%
Big Cajun I Peaking Power LLC	Generator	100.00%
Big Cajun II Unit 4 LLC	Generation project development company	100.00%
Cabrillo Power I LLC	Generator	100.00%
Cabrillo Power II LLC	Generator	100.00%
Camas Power Boiler Limited Partnership	Owns boiler in Camas paper mill in Washington	100.00%
Camas Power Boiler, Inc.	General partner in Camas Power Boiler Limited Partnership	100.00%
Conemaugh Power LLC	Generator (owns 3.72% of generator)	100.00%
Connecticut Jet Power LLC	Generator	100.00%
Devon Power LLC	Generator	100.00%
Dunkirk Power LLC	Generator	100.00%
Eastern Sierra Energy Company	Holds partnership interest in Saguaro facility	100.00%
El Segundo Power II LLC	Generation project development company; has filed for market-based rate authority	100.00%
El Segundo Power, LLC	Generator	100.00%
Elbow Creek Wind Project LLC	Wind project development company	100.00%
ESOCO, Inc.	Domestic holding company for individual ESOCO O&M companies	100.00%
Granite II Holding, LLC	Holding company for the inactive Batesville, Kendall and Denver City projects acquired from LS Power, LLC	100.00%
Granite Power Partners II, L.P.	Holding company for all LS Power, LLC’s equity interest in independent power projects acquired by NRG on 1/20/2001	100.00%
Hoffman Summit Wind Project, LLC	Wind project development company	100.00%
Huntley Power LLC	Generator	100.00%
Indian River Operations Inc.	Provided O&M services to Indian River Power LLC	100.00%

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Exhibit B-2

Subsidiary Name	Description	NRG
Indian River Power LLC	Generator	100.00%
Keystone Power LLC	Generator (owns 3.7% of generator)	100.00%
Lake Erie Properties Inc.	Ethanol project development company	100.00%
Long Beach Generation LLC	Generator	100.00%
Louisiana Generating LLC	Generator	100.00%
LSP-Nelson Energy, LLC	Generation project development company	100.00%
Meriden Gas Turbines LLC	Generation project development company	100.00%
Middletown Power LLC	Generator	100.00%
Montville Power LLC	Generator	100.00%
NEO Corporation	Holding company for NEO Freehold-Gen LLC	100.00%
NEO Freehold-Gen LLC	Generator	100.00%
New Genco GP, LLC	Holding company for Texas non-nuclear assets	100.00%
New Genco LP, LLC	Holding company for Texas non-nuclear assets	100.00%
Norwalk Power LLC	Generator	100.00%
NRG Arthur Kill Operations Inc.	Provided O&M services to Arthur Kill Power LLC	100.00%
NRG Astoria Gas Turbine Operations Inc.	Provided O&M services to Astoria Gas Turbine Power LLC	100.00%
NRG Bayou Cove LLC	Holding company for Bayou Cove Peaking Power, LLC	100.00%
NRG Cabrillo Power Operations Inc.	Provided O&M services to Cabrillo Power I LLC and Cabrillo Power II LLC	100.00%
NRG California Peaker Operations LLC	Provided operating services to Red Bluff and Chowchilla II peaker plants in northern California	100.00%
NRG Capital II LLC	Holds the membership interest in NRG Peaker Finance Company LLC	100.00%
NRG Development Company Inc.	Created to conduct development activities in the U.S.	100.00%
NRG Devon Operations Inc.	Provided O&M services to Devon Power LLC	100.00%
NRG Dunkirk Operations, Inc.	Provided O&M services to Dunkirk Power LLC	100.00%
NRG El Segundo Operations, Inc.	Provided O&M services to El Segundo and Long Beach power stations	100.00%
NRG Energy Center Dover LLC	Generator	100.00%

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Exhibit B-2

Subsidiary Name	Description	NRG
NRG Energy Center Harrisburg Inc.	Provides district heating services in Pennsylvania	100.00%
NRG Energy Center Minneapolis LLC	Provides district heating services in Minnesota	100.00%
NRG Energy Center Paxton LLC	Owns cogeneration facility and sells steam to NRG Energy Center Harrisburg	100.00%
NRG Energy Center Pittsburgh	Provides district heating services in Pennsylvania	100.00%
NRG Energy Center Rock Tenn LLC	Owns assets in connection with the sale of steam to Rock-Tenn Corporation in St. Paul, Minnesota	100.00%
NRG Energy Center San Diego LLC	Provides district heating and cooling services in California	100.00%
NRG Energy Center San Francisco LLC	Provides district heating and cooling services in California	100.00%
NRG Energy Center Smyrna LLC	Provides O&M services to Smyrna, Delaware's Warren F. Beasley plant	100.00%
NRG Energy Jackson Valley I, Inc.	General partner in Jackson Valley Energy Partners, L.P.	100.00%
NRG Energy Jackson Valley II, Inc.	Limited partner in (i) Jackson Valley Energy Partners, L.P., (ii) San Joaquin Valley Energy Partners I, L.P., (iii) San Joaquin Valley Energy Partners IV, L.P. and (iv) Bioconversion Partners, L.P.	100.00%
NRG Generation Holdings Inc.	Holding company for Texas assets	100.00%
NRG Granite Acquisition LLC	Acquisition company used to purchase LS Power, LLC's independent power project portfolio	100.00%
NRG Huntley Operations Inc.	Provided O&M services to Huntley Power LLC	100.00%
NRG Mesquite LLC	Limited partner of Kaufman Cogen LP	100.00%
NRG Middletown Operations Inc.	Provided O&M services to Middletown Power LLC	100.00%
NRG Montville Operations Inc.	Provided O&M services to Montville Power LLC	100.00%
NRG New Jersey Energy Sales LLC	Power marketing entity	100.00%
NRG New Roads Holdings, LLC	Holding company to hold title to certain Cajun assets	100.00%
NRG Norwalk Harbor Operations Inc.	Provided O&M services to Oswego Power LLC and Norwalk Power LLC	100.00%
NRG Operating Services, Inc.	Provides operations and maintenance services for operating affiliates	100.00%

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Exhibit B-2

Subsidiary Name	Description	NRG
NRG Oswego Harbor Power Operations Inc.	Provided O&M services to Oswego Power LLC	100.00%
NRG PacGen Inc.	Holding company which acquired 100% of the stock of Pacific Generation Company	100.00%
NRG Power Marketing Inc.	Power marketing entity	100.00%
NRG Rockford Acquisition LLC	Holding company for certain U.S. projects	100.00%
NRG Rockford II LLC	Generator	100.00%
NRG Rockford LLC	Generator	100.00%
NRG Rocky Road LLC	Inactive	100.00%
NRG Saguaro Operations Inc.	Operator of generator in Henderson, Nevada	100.00%
NRG South Central Generating LLC	Holding company for subsidiaries in south central region	100.00%
NRG South Central Operations Inc.	Provides operations and maintenance services for affiliates in South Central region	100.00%
NRG South Texas LP	Owns 44% undivided interest in South Texas Project	100.00%
NRG Sterlington Power LLC	Generator	100.00%
NRG Telogia Power LLC	Holds 50% interest in Telogia Power Inc.	100.00%
NRG Texas LLC	Holding company for NRG South Texas LP and NRG Texas LP	100.00%
NRG Texas LP	Generator	100.00%
NRG Thermal LLC	Holding company for district heating and cooling projects and other U.S. projects	100.00%
NRG West Coast LLC	Formed as holding company for west coast limited liability companies	100.00%
ONSITE Energy, Inc.	Domestic holding company for ONSITE Marianas Corporation and limited partnership interest in Turners Falls project	100.00%
Oswego Harbor Power LLC	Generator	100.00%
Pacific Generation Company	Holding company for certain U.S. subsidiaries	100.00%
Pacific Generation Holdings Company	Holds limited partnership interest in Project Finance Fund III	100.00%
Padoma Wind Power, LLC	Wind farm developer	100.00%
Saguaro Power Company, L.P.	Generator	50.00%

Exhibit B-2

Subsidiary Name	Description	NRG
Saguaro Power LLC	Holding company for Eastern Sierra Energy Company which owns a 50% interest in Saguaro Power Company	100.00%
San Joaquin Valley Energy I, Inc.	General partner in San Joaquin Valley Energy Partners I, L.P.	100.00%
San Joaquin Valley Energy IV, Inc.	General Partner in San Joaquin Valley Energy Partners IV, L.P. and Bioconversion Partners, L.P.	100.00%
San Juan Mesa Wind Project II, LLC	Wind project development company	100.00%
Somerset Operations Inc.	Provided O&M services to Somerset plant	100.00%
Somerset Power LLC	Generator	100.00%
Telogia Power Inc.	Owns 100% of Timber Energy Resources, Inc.	100.00%
Texas Genco GP, LLC	Holding company for ownership interests in South Texas Project	100.00%
Texas Genco Holdings, Inc.	Holding company for ownership interests in South Texas Project	100.00%
Texas Genco LP, LLC	Holding company for ownership interests in South Texas Project	100.00%
Vienna Power LLC	Generator	100.00%
WCP (Generation) Holdings LLC	Holding company for West Coast Power LLC	100.00%
West Coast Power LLC	Holding company for Cabrillo Power I LLC, Cabrillo Power II LLC, El Segundo Power, LLC, El Segundo Power II, LLC and Long Beach Generation LLC	100.00%

Exhibit C: Organizational Charts Depicting Current and Post-Transaction Structure

Attached are organizational charts that depict the pertinent corporate structure both before and after the Transaction. As described in Section III of this Application, Exelon may engage in certain additional reorganization to best align the assets of the two companies. Such additional reorganization will not involve PECO or ComEd.

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Exhibit C

Figure 1: Simplified Current Organization Chart for NRG Energy, Inc.

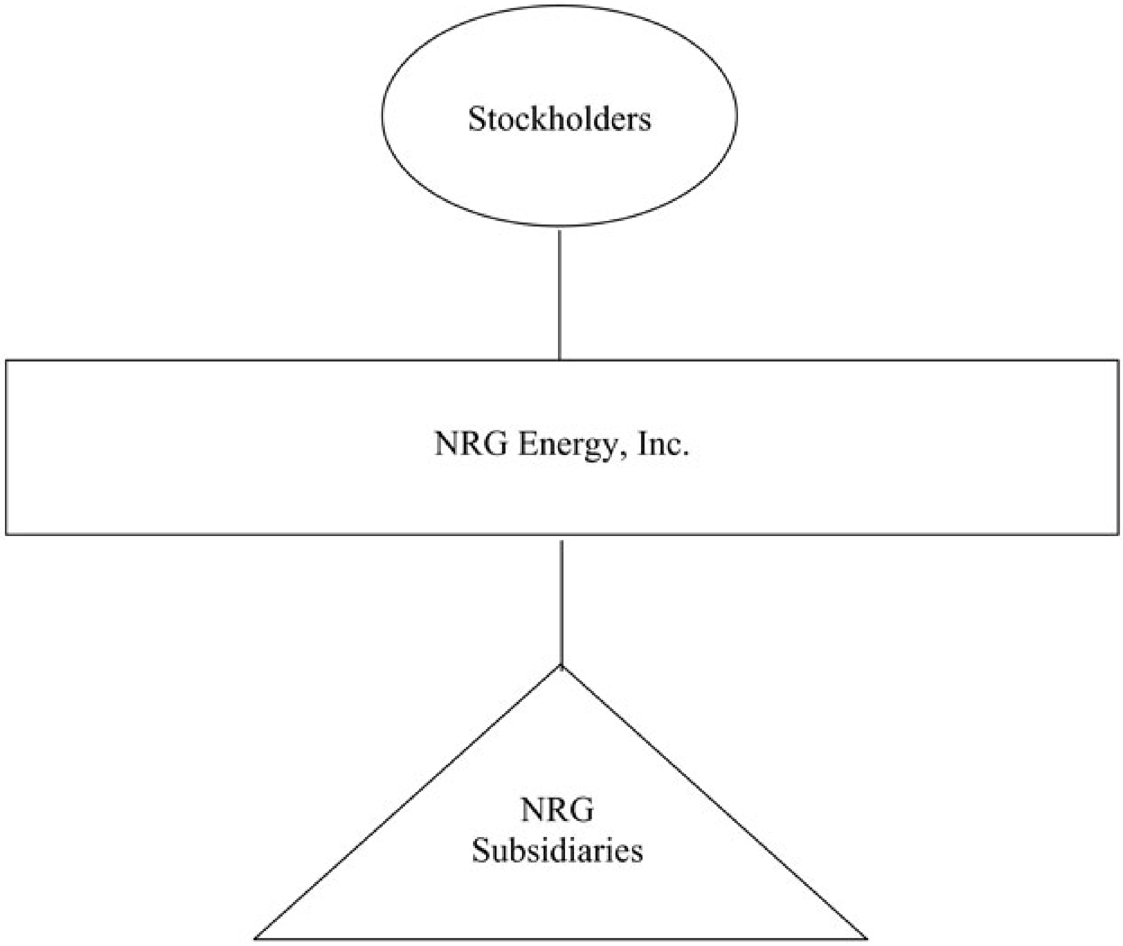

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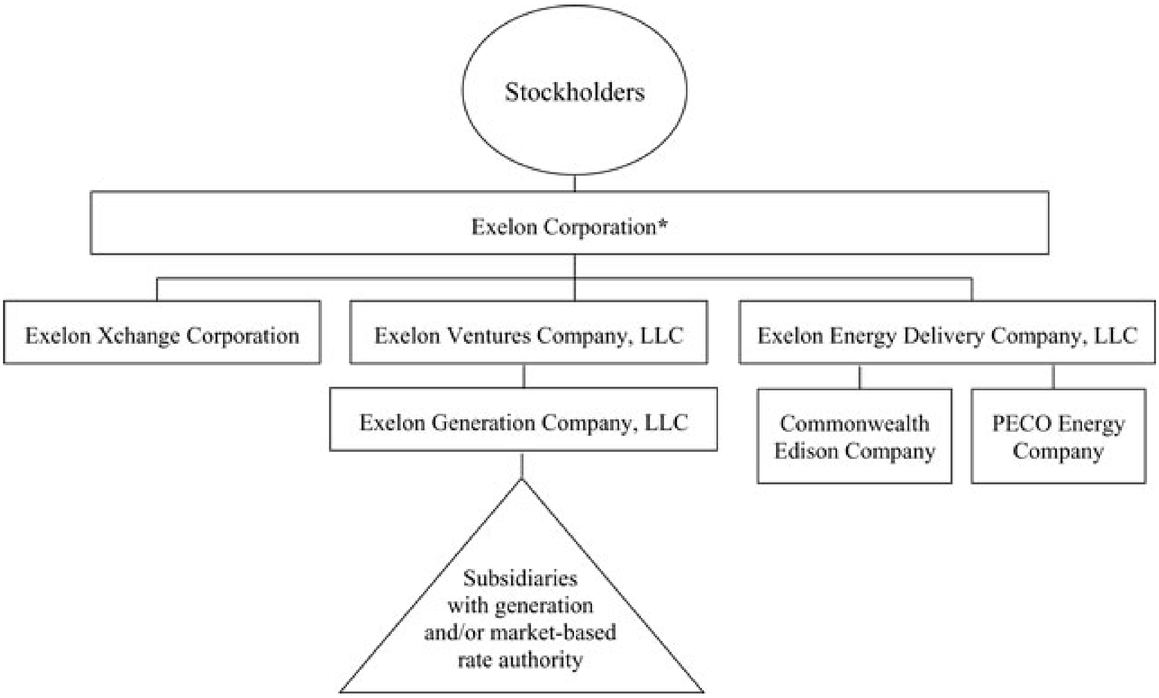
Figure 2: Simplified Current Organization Chart for Exelon Corporation



* Exelon has additional subsidiaries besides the subsidiaries identified. These other subsidiaries do not own generation assets and are not material to the Commission's review of the Transaction.

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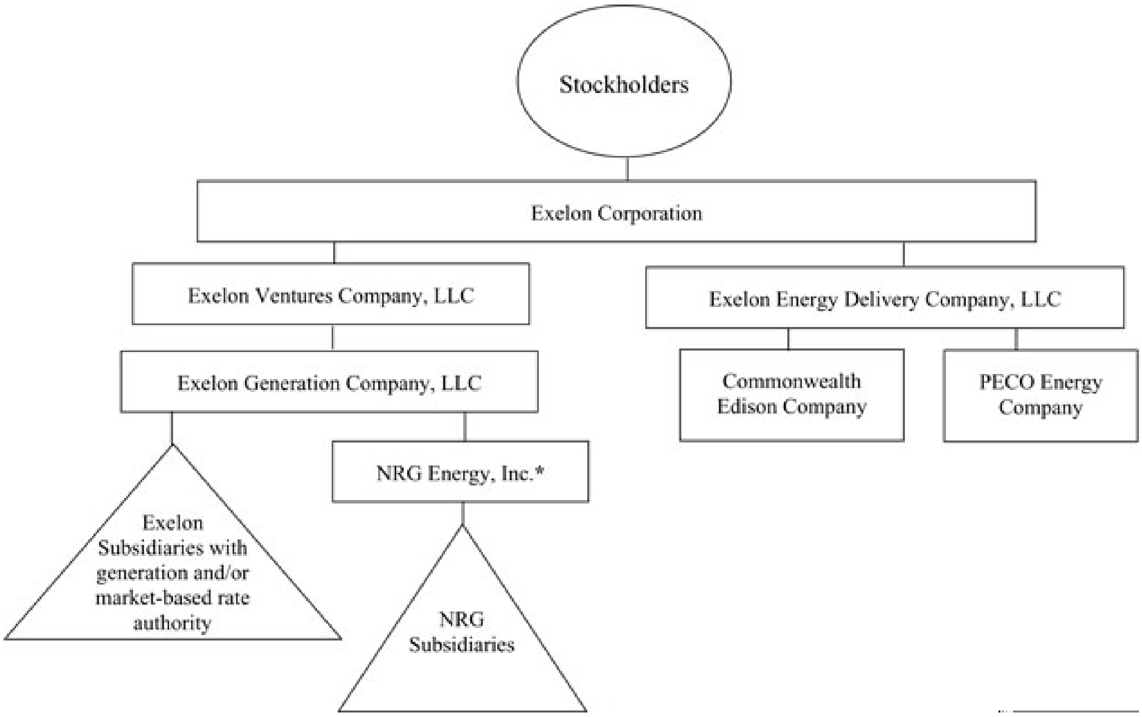
Figure 3: Simplified Proposed Final Structure Under Exchange Offer Structure



* Internal reorganizations may result in alternative structures, including either NRG Energy, Inc. being a direct subsidiary of Exelon Ventures Company, LLC or a merger of NRG Energy, Inc. into Exelon Generation Company, LLC

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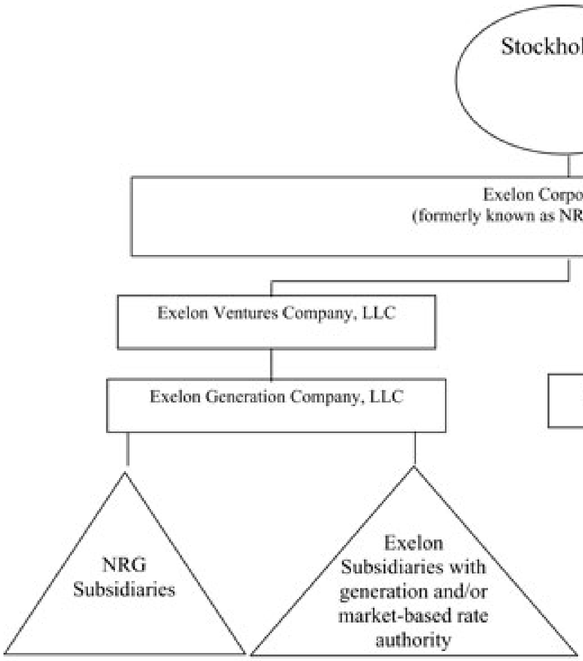
Figure 4: Simplified Proposed Organization Chart Under Negotiated Agreement



Note: This structure involves the merger of Exelon Corporation into NRG Energy, Inc. with NRG being the surviving corporation and NRG's subsidiaries becoming subsidiaries of Exelon Generation Company. A negotiated transaction also may result in one of the final structures described in Figure 3.

Exhibit D: Description of All Joint Ventures, Strategic Alliances, Tolling Arrangements or Other Business Ventures

A description of all of Exelon's joint ventures, strategic alliances, tolling arrangements and other business ventures appears below. Exelon is not aware of any joint ventures, strategic alliances, tolling arrangements and other business ventures of NRG that are not described in Exhibit B.

Exelon Ownership Interests in Joint Ventures:

Chicago Equity Fund (<10%)
Conemaugh Fuels, LLC (20.72%)
Dearborn Park Corporation (<10%)
I.L.P. Fund C/O Chicago Capital Fund (<10%)
Keystone Fuels, LLC (20.99%)
Northwind Windsor (50%)
NuStart Energy Development, LLC (10%)
PECO Energy Capital, LP (3%)

Exelon Ownership Interests in Generation:

Conemaugh Generating Station – Nuclear and Fossil (20.72%)
Keystone Generating Station – Nuclear and Fossil (20.99%)
Merrill Creek Reservoir Project – used for cooling water (44.24%)
Peach Bottom 2&3 – Nuclear (50%)
Quad Cities 1&2 – Nuclear (75%)
Salem Units 1&2 – Nuclear and Fossil (42.59%)

Exhibit E: Common Officers or Directors of the Parties to the Transaction

There are no common officers or directors between Exelon and NRG.

Exhibit F: Description and Location of Wholesale Power Sales Customers and Unbundled Transmission Services Served by Applicants or their Affiliates

PJM provides unbundled transmission service to ComEd and PECO transmission customers. Neither ComEd nor PECO has any unbundled transmission service customers.

Neither ComEd nor PECO has any wholesale power sales customers. Wholesale power sales customers served by Exelon’s Power Team and NRG are filed with the Commission in the Electronic Quarterly Reports. Accordingly, Exelon requests a waiver of the requirement with respect to wholesale sales made by Exelon’s Power Team and NRG.

Exhibit G: Description of Jurisdictional Facilities of Applicants and Their Affiliates

Exelon's NRG's and their affiliates' jurisdictional facilities are described in Parts II, III and V of this Application and in the testimony of William Hieronymus attached as Exhibit J.

Exhibit H: Jurisdictional Facilities and Securities Associated with or Affected by the Transaction

The jurisdictional facilities and securities associated with or affected by the Transaction are described in Parts II, III and V of this Application and in the testimony of William Hieronymus attached as Exhibit J.

Exhibit I: Contracts with Respect to the Disposition of Facilities

There are no contracts in effect with respect to the Transaction. However, Exelon is attaching its Form S-4 filing at the SEC, which describes in detail the terms and conditions of its tender offer to NRG's shareholders.

Exhibit J: Facts Relied upon to Demonstrate Consistency with Public Interest

The facts relied upon to show that the Transaction is consistent with the public interest are set forth in Part V of the Application and in the testimony of William Hieronymus attached as part of this Exhibit J.

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Exhibit J-1

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Exelon Corporation	**)**	**Docket No. EC09-______-000**

APPLICATION OF EXELON CORPORATION
UNDER SECTION 203 OF THE FEDERAL POWER ACT

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

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Exhibit J-1

DIRECT TESTIMONY OF
WILLIAM H. HIERONYMUS

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I. PURPOSE, SUMMARY OF ANALYSIS AND CONCLUSIONS

Introduction

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

Q. PLEASE SUMMARIZE YOUR RELEVANT PROFESSIONAL BACKGROUND.

A. For the past 32 years, the primary focus of my consulting has been on the electricity sector. For the past 20 years, I have worked primarily on the restructuring of the electricity industry from a fully regulated to a more competitively oriented model, both in the U.S. and abroad. Much of my time has been spent on market power issues. I have developed and commented on market power-related regulatory rules and Regional Transmission Organization ("RTO") (or foreign equivalent) market power mitigation as well as on issues of market structure. I have testified before the Federal Energy Regulatory Commission ("Commission") and other regulatory bodies on market power on numerous occasions. This includes a number of mergers and acquisitions over the past dozen years, including approximately 20 mergers among electric utilities and "convergence" mergers of electric utilities and natural gas pipelines. Among these, I was Applicant's market power witness in Docket No. EC00-26-000, the merger of Unicom and PECO Energy Company that formed Exelon Corporation, and in Docket No. EC05-43-000, the proposed merger of Exelon Corporation and Public Service Electric and Gas that ultimately did not occur. My resume is attached as Exhibit J-2.

Purpose

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have been asked by Exelon Corporation ("Exelon") and all its jurisdictional public utilities[1] (collectively, the "Applicant") to evaluate the potential competitive impact of the merger of Exelon and NRG Energy, Inc. ("NRG") on relevant electricity markets.[2] I performed the Competitive Analysis Screen described in Appendix A to the Commission's Merger Policy Statement ("Order No. 592"),[3] as modified in the Revised Filing Requirements Under Part 33 of the Commission's Regulations.[4] The Competitive Analysis Screen is intended to comport with the Department of Justice and Federal Trade Commission ("DOJ/FTC") Horizontal Merger Guidelines ("Guidelines"). I also have analyzed other electricity-related product markets (*e.g.*, ancillary services and capacity). I further provide analyses to show that the proposed mitigation cures all screen failures in all relevant markets.

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

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

2 The exhibits to the Application include a complete list of relevant affiliates of Applicant.

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

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

Summary of Analysis and Conclusions

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

A. No. Despite the fact that NRG and Exelon are two large generators in North America, there are only two markets where both have non-trivial amounts of generation. (See Table 1. below.)

Table 1: Summary of Generation Owned by Exelon and NRG

Balancing Authority Area[5]	Exelon	NRG
PJM	23,698	1,644
ISO-NE	178	2,204
NYISO	—	4,051
ERCOT	3,405	13,269
CAISO	—	2,633
MISO	1,043	—
NEVP	—	51
CSWS	795	—
EES/LAGN	853*	2,994
SOCO	933	—
Total	**30,052***	**26,847**

* The 853 MW connected to EES also is connected to ERCOT. The total removes the double count.

These two markets are PJM East,[6] which is a submarket of the PJM Interconnection, L.L.C. ("PJM") market and in some zones within the Electric Reliability Council of Texas, Inc. ('ERCOT"). Even in these markets, HHI changes are only slightly in excess of safe harbor levels and only in some time periods. Neither market is highly concentrated, and indeed, concentrations are at most at the low end of moderately concentrated. The Commission has previously approved mergers with similar screen results. Notwithstanding the modest competitive effects of the transaction, Exelon has proposed a mitigation plan that eliminates any screen failures and resultant competitive concerns that might have existed as a result of the merger. Its "clean sweep" approach commits to divesting all generation owned or controlled by Exelon in ERCOT, and all generation owned or controlled by NRG in PJM East. PJM East and submarkets within ERCOT are the only markets in which the combined firm would, absent mitigation, be a

5 The abbreviations in Table 1 (other than those already identified) are as follows: ISO-New England Inc. ("ISO-NE"), New York Independent System Operator, Inc. ("NYISO"), California Independent System Operator Corporation ("CAISO"), Midwest Independent System Operator, Inc. ("MISO"), the Nevada Power Company balancing authority are ("NEVP"), the Central and Southwest Services (also known as AEP-West) balancing authority area ("CSWS"), the Entergy Services, Inc. balancing authority area ("EES"), the Louisiana Generating, LLC ("LAGN") and the Southern Company Services, Inc. ("SOCO") balancing authority area.

6 A total of 8,454 MW of Exelon's PJM generation is in PJM East and 1,058 MW of NRG generating capacity is in PJM East.

significant supplier and in which both firms presently control non-trivial amounts of generation.[7] This clean sweep in these two markets cures even minor failures of the Commission's market power screen. There are no vertical issues arising from control over transmission or fuels supplies and delivery systems or any other potential entry barriers. Thus, once the proposed mitigation is taken into account, the merger does not raise competitive concerns. My analysis focuses on expected market conditions in 2009.

Q. PLEASE SUMMARIZE THE COMPETITIVE EFFECTS OF THE TRANSACTION IN PJM AND ERCOT.

A. PJM operates the largest centrally dispatched, competitive wholesale electricity market in the United States, with approximately 165,000 MW of installed generation. This market is well-functioning, and has in place comprehensive, Commission-approved market monitoring and mitigation procedures that mitigate concerns about generation and transmission market power. Exelon owns or controls via contract approximately 24,000 MW of generation in PJM,[8] approximately 14 percent of capacity installed in PJM (and a somewhat lower market share when imports are taken into consideration). NRG owns approximately 1,600 MW of generation in PJM, a share of installed capacity of less than one percent. As I describe in detail below, the PJM RTO-wide market is unconcentrated or at most in the lower part of the moderately concentrated range, and the HHI changes associated with this merger are within safe harbor thresholds, even before consideration of the planned generation divestiture.

The Commission has identified the PJM East submarket as a relevant geographic market in a number of contexts.[9] PJM East contains approximately 35,000 MW of installed

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7 Because the clean sweep of Exelon generation in ERCOT divests the contract giving it control over the 853 MW unit also connected to EES/LAGN, there is no overlap in that market post-divestiture.

8 Unless otherwise stated or by context, the generation ratings referred to in my testimony represent summer ratings.

9 *See*, for example, *Market-Based Rates For Wholesale Sales Of Electric Energy, Capacity And Ancillary Services By Public Utilities*, Order No. 697, 119 FERC ¶ 61,295 (2007) (codified at 18 C.F.R. Part 35) ("*Order No. 697*") at P 246, citing to *Exelon Corp*., 112 FERC ¶ 61,011 (2005) at P 122.

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generation. Exelon Generation owns or controls via contract approximately 8,454 MW of generation in PJM East, an approximately 24 percent share of installed capacity (and a somewhat lower market share when imports are taken into consideration). NRG owns 1,058 MW of generation in PJM East, an approximately 3 percent share of installed capacity (again, a somewhat lower market share when imports are taken into consideration). The PJM East market is moderately concentrated and the change in HHI would, absent divestiture, slightly exceed 100 points in three time periods (plus one off-peak period when the post-transaction HHI is less than 1000). Exelon has committed to divest the three generating stations owned by NRG in PJM East – Dover Energy (104 MW), Vienna (158 MW), and Indian River (796 MW).[10] As a result of this commitment, Exelon's share of this market will not increase and the competitive effect of the merger will be *de minimis*.[11]

While ERCOT is not itself a FERC-jurisdictional market, I analyzed the effect of the merger on competition in the ERCOT market in the same manner as if it were a FERC-jurisdictional market. ERCOT operates the electric grid and manages the deregulated market for approximately 75 percent of Texas. Because ERCOT is asynchronous with both the Eastern and Western Interconnections, imports from the rest of the United States are limited to capacity on high voltage direct current ("HVDC") ties with only 820 MW of capacity. Including imports, capacity in ERCOT is in excess of 80,000 MW. Exelon Generation owns or controls via contract approximately 3,400 MW of generation in ERCOT, an approximately 4 percent market share.[12] NRG owns approximately 13,000 MW of generation in ERCOT (including about 2,200 MW of mothballed generation), an approximately 16 percent market share. Exelon has committed to divest all of the

10 Two of the Indian River units (179 MW) are scheduled to be retired in 2010 and 2011.

11 Under the Commission's Delivered Price Test analysis, NRG will be allocated a pro rata share of import capacity into PJM East. However, since NRG owns only a very modest share of generation in PJM outside of PJM East, its allocated share of imports into PJM East is small, as discussed below in describing the results of the Competitive Analysis Screens.

12 Exelon currently has 190 MW of mothballed generation at Handley Units 1 &2 and Mountain Creek Units 2 & 3. Exelon has filed with ERCOT to permanently decommission these units in the first quarter of 2009. Our analysis assumes that they are not available to run at any time in the 2009 analysis year.

generating units it currently owns in ERCOT – Mountain Creek (788 MW),[13] Handley (1,262 MW), LaPorte (152 MW) – as well as the generation it contracts for under long-term PPAs – AES Wolf Hollow (350 MW) and Tenaska Frontier (853 MW).[14] As a result of these commitments, Exelon's post-transaction, post-divestiture generation will be identical to what NRG would control without the transaction and hence, the competitive effect of the merger will be *de minimis*.

Q. ARE THERE MATERIAL COMPETITIVE EFFECTS IN MARKETS OUTSIDE OF PJM AND ERCOT?

A. No. While the merging parties each own or control generation outside of PJM and ERCOT, the extent of business transactions in other markets where both own generation is *de minimis*.

Exelon has affiliated generation located in ISO-New England Inc. ("ISO-NE"), Midwest Independent System Operator, Inc. ("MISO"), the Central and Southwest Services (also known as AEP-West) balancing authority area ("CSWS"), the Southern Company Services ("SOCO") balancing authority area, and the EES balancing authority area.

NRG owns or controls generation in ISO-NE, the New York Independent System Operator, Inc. ("NYISO"), California Independent System Operator Corporation ("CAISO"), the Nevada Power Company balancing authority area ("NEVP"), and the Louisiana Generating, LLC ("LAGN") and Entergy ("EES") balancing authority areas. NRG's generation in the LAGN balancing authority area uses the transmission system of Entergy, and, for analytic purposes, is treated as if located in the EES balancing authority area.[15]

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13 These ratings for Handley and Mountain Creek include the approximately 190 MW of currently mothballed capacity that is scheduled to be decommissioned. The capacity figures reported in the text excludes the 190 MW that will be retired.

14 Tenaska Frontier is the unit referenced previously that is capable of being interconnected directly onto both the ERCOT and Entergy ("EES") balancing authority area grids. The total MW reported for Frontier represents its summer-rated capacity as reported by ERCOT. The contractual amount is 830 MW. 300 MW of the output of the Frontier facility is currently under contract to Entergy and is dispatched in the EES balancing authority area.

15 LAGN is a transmission–dependent balancing authority area that utilizes the transmission systems of its transmission providers (primarily Entergy) to transmit energy from its generating units to its customers.

Thus, only one of the two merging parties owns or controls generation in MISO (Exelon), CSWS (Exelon), NYISO (NRG), CAISO (NRG), SOCO (Exelon) and the NPC balancing authority area (NRG). In these markets, "the merging entities do not currently conduct business in the same geographic markets,"[16] and hence there is no material competitive effect.

In the remaining two markets, ISO-NE and EES/LAGN, the extent of business transactions in the same geographic markets is sufficiently *de minimis* that no competitive concerns are raised and a full competitive analysis screen is not required.

In ISO-NE, a market with approximately 31,000 MW of installed generation, Exelon Generation owns approximately 178 MW of generation, less than a one percent share of installed capacity. This generation has high variable costs and rarely runs. NRG owns approximately 2,200 MW of generation in ISO-NE, about a 7 percent share of installed capacity (and a somewhat lower market share when imports are taken into consideration). ISO-NE is an unconcentrated market and Exelon's and NRG's shares are small. The HHI change at peak times is approximately 8 points. Moreover, there are no submarkets within ISO-NE that are relevant in the context of this merger. The identified load pockets in ISO-NE include Northeast Massachusetts (NEMA)/Boston, Southwest Connecticut ("SWCT") and Connecticut ("CT"). While all but about 130 MW of NRG's 2,200 MW of generation is located in the SWCT and CT load pockets, none of Exelon's generation is located there. Similarly, while 107 of Exelon's 178 MW of generation in ISO-NE is located in the NEMA/Boston load pocket, none of NRG's generation is located there.

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16 18 C.F.R. § 33.3(a)(2)(i). Because Exelon's share of ISO-NE installed capacity is very small (less than one percent), its allocable share of the interface into NYISO will be truly trivial. As I discuss in more detail below, there also are no concerns raised by the possibility of potential imports between PJM and NYISO.

Hence, the relevant market is ISO-NE as a whole, and, clearly, the effect of the merger in ISO-NE is not material.

EES is a balancing authority area market with approximately 42,000 MW of installed generation. The only generating asset owned or controlled by Exelon Generation in EES is the Tenaska Frontier facility (853 MW), which is controlled by it as a result of a long-term PPA, and is interconnected to both EES and ERCOT.[17] The Tenaska Frontier facility represents about 2 percent of installed capacity in EES. NRG owns or controls approximately 3,000 MW of generation in EES/LAGN, an approximately 7 percent share of installed capacity. Both shares would be lower if imports were taken into consideration. The HHI change with imports ignored is about 29 points. Notably, the majority of the output of NRG's generating facilities located in the LAGN balancing authority area is used to supply requirements load under long-term contracts to several distribution cooperatives and public power authorities.[18] Further, as already noted in the preceding discussion of the impact of the merger in ERCOT, Exelon has committed to divest the generation it controls under the Tenaska Frontier contract. Tenaska Frontier is the only Exelon-controlled generating unit connected to the EES transmission system. As a result of these commitments, the share of the combined company in EES will be NRG's pre-merger share and hence, the competitive effect of the merger will be *de minimis*.

17 Recall that 300 MW of this generation is subject to an agreement under which Entergy is purchasing energy through April 2010, and then 150 MW through April 2011.

18 Indeed, NRG has reported that "During limited peak demand periods, the load requirements of these contract customers exceed the baseload capacity of NRG's coal-fired Big Cajun II plant. During such peak demand periods, NRG typically employs its own gas-fired assets, or alternatively purchases power from external sources frequently at higher prices than can be recovered under the Company's contracts." Big Cajun II accounts for about half of NRG's generating assets in the LAGN balancing authority area.
NRG's December 31, 2007 10-K, page 30.
http://www.snl.com/Cache/5681447.pdf?O=3&IID=4057436&OSID=9&FID=5681447

Q. WHAT IS THE PLAN FOR INTERIM MITIGATION PRIOR TO DIVESTING NRG'S GENERATION IN PJM EAST AND EXELON'S GENERATION AND CONTRACTS IN ERCOT?

A. Exelon will not be able to divest the generation until the transaction is closed. Inevitably, there will be a period between closure and when divestiture contracts can be negotiated and necessary regulatory approvals (including approvals by FERC and the antitrust authorities) have been granted. Under these circumstances, the Commission generally has required interim mitigation.

With respect to the PJM East market, the general interim mitigation commitment is to bid all energy and capacity of the units listed in Appendix 1 to the Application at or below mitigated prices determined according to PJM rules.[19] As described in the application and below, all PJM capacity resources are required to offer energy into the day ahead market. Hence, there is no issue of physical withholding of energy.[20] The mitigated energy bids will be based on mitigated prices that in turn are based on costs computed according to PJM Cost Development Task Force ("CDTF") rules. PJM rules for mitigated bids allow a margin over costs so-defined, generally 10 percent, but a higher fixed percentage or $/MWh adder for Frequently Mitigated Units. Since the mitigation is an upper limit on prices, Exelon may bid below these cost-based levels. Consistent with current practice, some units, most notably the pumped storage capacity, will be bid in as must run and hence be a price taker in the market. The bidding of Exelon's existing and newly acquired shares of Keystone and Conemaugh (which are not PJM East units) is controlled by Reliant Energy Northeast Management Company, and not Exelon, as noted below.

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19 As described in the Application, there are two old, small Exelon units that are not PJM capacity resources and are not bid into the PJM market. There also is a cogeneration resource, Grays Ferry, for which Exelon offers into PJM and from which Exelon has the right to energy dispatched onto the grid but that Exelon does not dispatch or otherwise control. It also is not subject to interim mitigation.

20 Violation of RTO rules subjects the offender to draconian sanctions.

Exelon also is committing to bid into the capacity market at or below mitigated prices. If any RPM Base Residual Auctions take place during the interim period, Exelon commits to bid all of the PJM East capacity in at prices no higher than the PJM-approved Market Seller Offer Caps. Any capacity that remains unsold and is not being used to cover a deficiency in capacity sold in the Base Residual Auction at the time of any interim (*i.e.*, incremental) RPM auction will be bid at or below the mitigated rate computed according to the existing PJM mitigation protocol for such auctions. This rate is the higher of 110 percent of the clearing price in the most recent Base Residual Auction or the unit's Market Seller Offer Caps.

As discussed elsewhere in this testimony, the transaction raises no market power concerns in the two market-based PJM ancillary services markets. These are not PJM-East markets but rather are markets that span the substantial majority of PJM. Consistent with results for energy, Exelon's and NRG's share of ancillary services capacity in these larger markets is too small to raise market power concerns. Notwithstanding that the there is at most a small increase in Exelon's market share of PJM ancillary services in the interim period, Exelon is proposing to limit its bids into the ancillary services markets to cost-based bids computed according to existing PJM rules.[21] Participation in PJM ancillary services markets is voluntary and it is not at all clear how a must-offer commitment to assure that there is no physical withholding could be crafted.[22] However, even if there were reason to be concerned that Exelon will have gained material market power in the interim period, which there is not, there still would be no serious concern with physical withholding. PJM co-optimizes energy and the two ancillary services, so that all capacity bid to produce any of the three products can affect the price of all of the products. Since PJM rules require that all PJM capacity resources (which include all of the PJM East mitigated units) be bid into the energy market, capacity cannot be withheld from this co-optimized market. Hence, the mitigated bidding commitments for energy substantially inhibit any possible impact of Exelon's withholding bids from the ancillary services markets.

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21 Exelon's and NRG's bids into the synchronous reserve market already are mitigated to these levels, as are the bids for all PJM generators.

22 Since these ancillary services can only be provided from units that are synchronized to the grid, a must-offer requirement in the real time market would require that all mitigated units be operating, which would be grossly inefficient since out-of-merit units would be consuming the fuel needed to sit at their lower operating levels.

Exelon also is offering interim mitigation for the ERCOT market. The structure of the ERCOT market lends itself less readily to interim mitigation than PJM. In particular, unlike PJM where all energy must be bid into and clear in the PJM markets, ERCOT is organized on the basis of bilateral transactions and balanced schedules, with only a small proportion of energy transacted in the ERCOT balancing energy market. Fortunately, a corollary of the balanced schedule requirement is that the substantial majority of economic generation in ERCOT is sold bilaterally for at least intermediate periods.[23] The capacity that will be controlled by Exelon post-transaction is no exception; hence, most of Exelon's ERCOT capacity is likely to have been pre-committed bilaterally for at least a substantial part of the interim period at prices negotiated separately by Exelon and NRG prior to closing.

In any event, there is no basis to conclude that the transaction will create a pre-divestiture market power problem in the ERCOT bilateral energy market. While I have identified screen failures in two of the ERCOT zonal markets, it is notable that the balanced schedules submitted by market participants need not be feasible, in the sense of not causing inter-zonal congestion. For this reason, a bilateral buyer need not co-locate its load and delivery points. Hence, the screen failures within zonal markets cannot signal a cause for concern with respect to competition in the bilateral energy market. As noted above, the ERCOT-wide energy market is unconcentrated post-merger and pre-divestiture, and there are no pre-divestiture screen failures. Hence, there is no need for interim mitigation of the bilateral energy market. There is no capacity market in ERCOT. While there are insufficient data available to model ancillary services market structures explicitly, there is no reason to anticipate that there would be structural issues (screen

23 We have no direct public data on the terms of wholesale electricity contracts. Wholesale electricity contracts are sold primarily to load serving entities that need to hedge fixed price contracts with retail customers. A review of retail offerings in ERCOT indicates that a one year term is the most common fixed price offering, though both longer and shorter products are available.

failures) in ERCOT-wide ancillary services markets (i.e., markets for ancillary services other than balancing energy). There is nothing about Exelon's and NRG's ERCOT generation unit characteristics to suggest that their shares of ancillary services capability are notably different than their shares of energy production capability. The market-priced ancillary services, with the exception of balancing energy, are procured on an ERCOT-wide basis. Therefore, there is no reason to believe that there is a need to mitigate bids into the ERCOT ancillary services markets with the possible exception of balancing energy.

While ERCOT administers the balanced schedule dispatch and ancillary services other than balancing energy on an ERCOT-wide basis, the balancing energy market clears on a zonal basis. The screen failures in the Houston and North zones could signal a basis for concern that increased concentration within a zone could result in market power that would be used to drive up congestion costs. In particular, since the balancing energy market is used as a tool for managing zonal congestion, it is theoretically possible to raise balancing energy prices by using market power within a zonal market.

In order to moot potential concerns over market power in the ERCOT zonal energy markets, Exelon has committed as interim mitigation to offering all of the fossil energy it will control in ERCOT that is available to balancing energy markets (i.e., is on line and not already committed to a buyer's balanced schedule or to previously cleared ancillary service markets) at the Out of Merit Energy Up mitigated prices computed by ERCOT.

As is the case in PJM, it is not practicable to develop interim mitigation that expressly guards against physical withholding in mitigated ancillary services markets, in this case, the balancing energy market. Balancing energy necessarily comes from units synchronized to the grid. There are entirely legitimate reasons why not all units are synchronized all the time, and a requirement that these units offer all of the energy they could produce that is not committed bilaterally would wastefully require that uneconomic units be committed to operate continuously at lower operating levels in the unlikely event that they are needed for balancing energy purposes.

Any theoretical concern with physical withholding of balancing energy is substantially mitigated by the fact that the ERCOT market operator is not passively reliant on the balancing energy market to solve congestion and preserve reliability. It also manages congestion with Out of Merit Energy, Out of Merit Capacity and Reliability Must Run ("RMR") generation. ERCOT's ability to schedule Out of Merit Capacity on a day-ahead basis (and intra-day if necessary) and Out of Merit Energy on a real time basis substantially inhibits any theoretical ability to physically withhold capacity needed for congestion management. If a unit is not running but could be used beneficially, the system operator can instruct that it be committed at a mitigated cost of bringing the unit to its lower operating level. If a unit is useful in real time (including but not limited to units committed as a result of Out of Merit Capacity instructions), the system operator can increase its output with an Out of Merit Energy instruction. Out of Merit Energy and Capacity prices and RMR energy prices also are not subject to elevation as a result of economic withholding since prices are mitigated by existing ERCOT rules on a cost-related basis.[24]

Q. ARE THERE ANY POTENTIAL ISSUES THAT THE ERCOT MITIGATION DOES NOT MOOT?

A. The ERCOT interim mitigation proposal relies on the ERCOT system operator using Out of Merit scheduling to defeat any possible physical withholding. Given the tools available to ERCOT and the relatively small amounts of Exelon's existing generation that is retained in the interim period, any concerns arising from reliance on Out of Merit scheduling in the interim are tenuous. Nonetheless, to the extent this is deemed to be a concern, Exelon is proposing an alternative form of mitigation. The genesis of this form of mitigation is primarily to eliminate the potential to use the assets scheduled for divestiture (the current Exelon assets) to enhance the profits earned by the acquired NRG assets by physically

24 Mitigated Out of Merit Energy prices are based on fuel costs and a heat rate that is generic to the type of unit being deployed. Only if generic heat rates are inappropriate to the specific unit being mitigated can the owner petition for a higher rate. Out of Merit Capacity is paid a generically determined cost of ramping to and holding at a unit's lower operating level. The system operator can, and does, take costs into account in choosing what units to call on out of merit.

withholding them and secondarily to limit the possible impact of the temporary retention of these assets on incentives to withhold the assets being acquired from NRG. The nub of this alternative mitigation proposal is to fully eliminate the ability to physically or economically withhold the generation scheduled for divestiture.

Exelon's alternative mitigation proposal begins with turning the Mountain Creek and Handley stations' relationship with ERCOT markets over to a third party Qualified Scheduling Coordinator ("QSE"). In ERCOT, QSEs are the market participants and there are several who act as agents for generation owners or entities serving retail customers. The contractual relationship with the QSE will be structured to insure that it has an incentive to maximize the profitability of controlled assets and is insulated from any incentive to advantage Exelon-owned assets that it does not control. The QSE will fully control all aspects of the bidding of these stations. Because the QSE will control only a subset of the assets currently controlled by Exelon and none of the NRG assets, there can be no valid concern that this arrangement will result in enhanced market power relative to the pre-merger condition.

For reasons that include contractual issues with counterparties, this third party control form of mitigation is not adaptable to some of the generation Exelon controls in ERCOT. Primarily, this relates to its PPAs deemed to give it control over Tenaska/Frontier and Wolf Hollow. The complexity of contractual issues with respect to these units precludes simply turning operational concern over to other entities. Hence, Exelon proposes to retain bidding control over these units. To militate against physical withholding, Exelon would propose that each of these units will be scheduled to operate each day that they are not on outage and that the available capacity of these units (physically dispatchable capacity that was not pre-committed in the day-head schedules as either bilaterally dedicated for energy or for ancillary services) would be bid into the ERCOT balancing energy market at the mitigated prices discussed above. This assures that all available output from these units will be available to the ERCOT market at either contractually agreed or mitigated prices. In the case of the Tenaska/Frontier station, the amount of generation available to the ERCOT market will not include the 300 MW (two combustion turbine units) of capacity that are used to supply the long term contract with Entergy and are synchronized to the

Eastern Interconnection. There also are contractual and operational issues precluding simply turning control of the LaPorte peaking unit in the Houston zone over to a third party QSE. To mitigate possible physical withholding of this unit, Exelon proposes as part of this alternative to bid the full uncommitted capacity of the LaPorte station into the ERCOT balancing market. The sole difference between the LaPorte-related mitigation and the mitigation for the PPAs is that LaPorte, being a peaking station that rarely is synchronized to the ERCOT grid, will be bid into that market as a quick start unit. As with the other units scheduled for divestiture that Exelon will retain control of during this interim period, bids will be limited to those allowed by ERCOT cost-based bid mitigation.

Under this alternative scheme of mitigation it could be argued that there remains a possibility of physically withholding generation by manipulating outage schedules. In the case of the units turned over to third parties, there is no incentive to do so since the QSE controlling these units has no interest in any profits earned by Exelon units it does not control and has an incentive to maximize the profits earned by its controlled units. For the two large stations controlled under PPAs, Exelon has no operational control and hence cannot falsely declare a forced outage nor schedule an unforced outage to affect the market. With respect to the LaPorte unit, it also is dispatched by a third party, Air Products, but Exelon does have some contractual right to schedule outages. This outage schedule must be submitted to ERCOT well in advance and approved by it. Hence, outage manipulation of the idiosyncratic and episodic nature relevant to units like LaPorte is not feasible.

Another possible objection to this mitigation proposal is that there is no mitigation of the NRG units. In theory, during the interim period, the ownership of the existing Exelon units could give it an incentive to bid the NRG units differently than NRG bids them today or than Exelon will bid them after the existing Exelon units are divested. Recall, however, that there is a market power issue to be resolved in ERCOT only when constraints cause it to fragment into zonal markets. Hence, this incentive issue will relate only to NRG assets within the zone containing the assets to be divested. In the North zone, the only NRG generation is Limestone, a baseload coal station. It simply is not plausible to postulate withholding a deep baseload unit to raise the prices earned by higher cost gas-fired generation. Megawatt-by-megawatt, this patently is a losing proposition. In the Houston zone, there is a much greater variety of NRG generation. However, the only generation being added to the NRG fleet in Houston is LaPorte, a high-cost peaker that is further up the supply curve than most of NRG's generation in Houston. In that sense, LaPorte is an "incentive" unit that could theoretically benefit from withholding NRG generation in the Houston zone only if it is in merit. To be profitable, this would require that a still-higher cost NRG-owned peaker be withheld to increase the market price in the zone. Since LaPorte rarely runs, and would gain little on these occasions, the incentive for withholding is small.

Q. WHAT DO YOU CONCLUDE FROM THESE INTERIM MITGATION PROPOSALS?

A. Either of the proposals robustly mitigates any increase in market power that may exist in the interim period. The primary proposed mitigation, which I understand to be preferred by Exelon, ensures that bidding commitments in PJM will effectively eliminate Exelon's ability to economically withhold generation and market rules effectively eliminate physical withholding. In ERCOT, there is no material competitive effect of the transaction in ERCOT-wide markets and the mitigation relies on market rules to effectively eliminate physical withholding. Exelon's proposal to cap its bids into the balancing market to the ERCOT-determined Out of Merit Energy Up rate eliminates the possibility of economic withholding. The alternative form of mitigation discussed immediately above, should the Commission require it, would fully mitigate the potential to exercise either physical or economic withholding with respect to the units that subsequently will be divested. The mechanism is somewhat different, relying in part on turning control of some of Exelon's divestible generation over to a third party, but the effect is to maintain the lack of a combined bidding strategy for NRG and Exelon legacy generation that exists prior to the Transaction.

Finally, I would make two general points about the ERCOT and PJM markets. First, both markets have market monitors who watch market behavior intently. Both ERCOT and PJM have substantial capabilities to curtail market behaviors that are deemed objectionable and to report such behaviors to the relevant regulatory bodies for further sanctions. Second, in both PJM East and ERCOT, Exelon proposes that interim mitigation apply to all of the capacity that it controls despite the fact that the amount of capacity to be divested, the divestiture of which will end interim mitigation, is a small fraction of the capacity it will control post-transaction. This “tail wagging the dog” interim mitigation likely will more tightly constrain Exelon’s bidding behavior than is the case today or will be the case after divestiture is accomplished and interim mitigation ended.

Q. ARE THERE ANY VERTICAL MARKET POWER ISSUES RAISED BY THIS MERGER?

A. No. The merger creates no material vertical market power issues. There are no issues related either to transmission ownership and operation, or to the merger-related combination of electric generation assets with fuels supplies or fuels delivery systems. Exelon’s transmission systems (owned by PECO and ComEd) are controlled by PJM. NRG owns no transmission other than the equipment necessary to connect its generation facilities to the grid.

Neither Exelon nor NRG owns any interstate gas transmission pipelines. PECO operates an intrastate natural gas distribution system in four counties that surround, but do not include, the city of Philadelphia. Its gas service area includes several third-party industrial customers and small generators, only a few of which use natural gas for generation other than as start-up fuel or backup. The few that are gas-fired generators are Merck (28 MW), Kimberly Clarke (55 MW), Crozier Chester Hospital (3 MW) and Hills at White Marsh (2 MW). Such limited local distribution operations do not provide Exelon an opportunity to use such control to favor affiliated activities, raise rivals’ costs or otherwise disadvantage rivals.[25]

25 In its Order in Docket No. EC05-43, the Commission found that PECO’s gas distribution facilities (and PSEG’s somewhat more extensive facilities) created no vertical market power issues, primarily because upstream and downstream markets were not highly concentrated (112 FERC ¶61,011 (2005) at P. 200-202). The finding that the upstream market was not highly concentrated was in spite of the fact that the combined upstream market share of Exelon and PSEG (measured as their share of gas transmission capacity reservations) was 36 percent, contributing 1,270 HHI points to the upstream market total of 1,572. Exelon’s share was 6 percent. Since NRG holds a very much smaller share of pipeline reservations than did PSEG, as I discuss below, the merged company’s share of the market, and hence the HHI, is would be much smaller. Stepping back from the formality of the vertical analysis called for in the Commissions regulations, common sense dictates that since there is a clean sweep in the proposed transaction whereas there was an increase in applicants’ downstream market share in the Exelon-PSEG transaction, the vertical concern surely should be less in this transaction.

Given Exelon's commitment to divest all of NRG's generation assets located in PJM East, which includes the territory served by PECO's gas distribution system, there clearly are no vertical concerns raised by combining Exelon's limited gas operations and NRG's generation in PJM. The remainder of NRG's generation in PJM is located in far western Pennsylvania (139 MW) and Illinois (447 MW).

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

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

II. DESCRIPTION OF THE PARTIES

Exelon

Q. PLEASE DESCRIBE EXELON.

A. Exelon, a registered public utility holding company, is the parent corporation of *inter alia* PECO, ComEd, and Exelon Generation.

Exelon Generation is a public utility that owns and operates electric generating facilities and engages in wholesale power and energy marketing and trading operations in the United State pursuant to Commission-approved market rate authority. All of the ownership interests in Exelon Generation are indirectly held by Exelon. Exelon Generation, through its subsidiaries, owns or controls via long-term contract approximately 30,000 MW of generation, primarily in PJM (24,000 MW), ERCOT (3,400 MW (excluding units scheduled for decommissioning prior to the transaction closing)), MISO (1,000 MW) and smaller amounts in ISO-NE and in the CSWS, SOCO and EES balancing authority areas. More than half of its generation capacity is nuclear. See Exhibit J-3.

Q. PLEASE DESCRIBE PECO AND COMED.

A. Exelon's energy delivery business consists of the regulated sale of electricity and distribution services by ComEd in northern Illinois and PECO in southeastern Pennsylvania (Philadelphia). Neither ComEd nor PECO owns or controls generation. ComEd and PECO also are the passive owners of transmission assets operationally controlled by PJM and regulated under the PJM tariff. In addition, PECO is engaged in the regulated sale of natural gas and distribution services in the Pennsylvania counties surrounding Philadelphia. PECO does not own or control any interstate gas transmission facilities or gas supplies.

The states of Pennsylvania and Illinois have retail access for electricity customers, and both PECO's and ComEd's customers have the right to choose competitive energy suppliers. The majority of retail customers in PECO's service territory continue to be served by PECO at generation rates that are capped through December 31, 2010. PECO procures generation to serve its retail customers from a PPA with Exelon Generation. Illinois is transitioning its procurement rules for providers of last resort. Initially, all power to serve such customers was procured by the local utility (if a regulated investor owned utility) via a simultaneously administered descending clock auction managed by the Illinois Commerce Commission (“ICC”). The amount that any supplier could supply was limited and Exelon Generation won 35 percent of the total ComEd requirement.[26] One-third of the contracts expire in each of three years. The first year’s contracts have lapsed. The auction system has been replaced by a single procurement administered by a state agency. Unlike the descending clock auction, which required the bidding of physical generation, the state agency procurement is for financially firm contracts, not physical generation. Hence, it is possible that none of the generation used to serve investor-owned utility load in Illinois (including ComEd load) will be “committed” after 2010.[27]

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

A. Exelon Energy Inc. (“Exelon Energy”) is a retail energy marketer supplying electricity and natural gas to commercial and industrial customers. Exelon Energy currently markets electricity to customers in Illinois and natural gas and renewable energy products to customers in Illinois, Michigan, and Ohio.

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26 While Exelon Generation was limited to 35 percent of total ComEd contracts, there was no limit on whether the 35 percent would be one, two or three year contracts. Exelon Generation in fact won nearly all of the three year contracts, so that most of its load obligations will continue into the 2009 year covered by this analysis and, more importantly, through or well into the time period for which interim mitigation will apply.

27 It is not at all clear how the Commission’s definition of Available Economic Capacity will evolve to be applied to this type of market. A quite plausible outcome will be that the issue never will be ripe since the concept of Available Economic Capacity in a market where no entity has regulated load responsibility may itself lack meaning. While it is not possible fully to predict what state regulators and legislatures will do, it seems most likely that in all of the areas of PJM where Exelon will have generation or load, AEC will have lost its meaning by 2010.

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NRG

Q. PLEASE DESCRIBE NRG.

A. NRG is a wholesale power generation company, engaged primarily in the ownership and operation of electric generating facilities, transacting in fuel and transportation services, and the marketing and trading of energy, capacity and related products in the United States and internationally.

NRG, through its subsidiaries, owns or controls approximately 26,000 MW of generation throughout the United States, primarily in ERCOT (13,300 MW), NYISO (4,000 MW), EES/LAGN (3,000 MW), CAISO (2,600 MW), ISO-NE (2,200 MW), PJM (1,500 MW) and the Nevada Power (NEVP) balancing authority area (50 MW). See Exhibit J-4.

NRG also owns generating facilities in Australia (605 MW) and in Germany (475 MW).

A subsidiary of NRG, NRG Thermal LLC, owns and operates district energy systems and combined heat and power plants nationwide, including in Harrisburg and Pittsburgh, Pennsylvania. Another subsidiary, NRG Engine Services provides engine maintenance and parts supply. Padoma Wind Power, LLC is a subsidiary that is a wind energy development company that has several wind projects under active development, as well as a pipeline of wind projects under development as joint ventures with third parties. These projects are in several states, including California and Texas.[28]

NRG owns no transmission or distribution facilities other than those necessary to connect its generating facilities to the grid.

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28 The planned wind projects in ERCOT are included to the extent they are scheduled to come on-line by 2009.

III. FRAMEWORK FOR THE ANALYSIS

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

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

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

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

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

Horizontal Market Power Issues

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

A. In December 1996, the Commission issued Order No. 592,[29] the “Merger Policy Statement,” which provides a detailed analytic framework for assessing the horizontal market power arising from electric utility mergers. This analytic framework is organized around a market concentration analysis. The Commission adopted the DOJ/FTC *Horizontal Merger Guidelines* for measuring market concentration levels by the Herfindahl-Hirschman Index (“HHI”).[30] On November 15, 2000, the Commission issued its Revised Filing Requirements Under Part 33 of the Commission’s Regulations,[31] which affirmed the screening approach to mergers consistent with the Appendix A analysis set forth in the Merger Policy Statement, and codified the need to file a screen analysis and the exceptions therefrom.

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29 Order No. 592, FERC Stats and Regs. ¶ 31,044 (1996).

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

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

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

If a proposed merger raises no market power concerns (*i.e.*, passes the Appendix A screen), the inquiry generally is terminated. Both the Merger Policy Statement and the Revised Filing Requirements accept that merger applications involving no overlap in relevant geographic markets do not require a screen analysis or filing of the data needed for the screen analysis.[32]

Q. WHAT PRODUCTS HAS THE COMMISSION GENERALLY CONSIDERED?

A. The Commission generally has been concerned with three relevant product markets: non-firm energy, short-term capacity (firm energy) and long-term capacity.[33] Both Economic

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

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

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

Capacity and Available Economic Capacity[34] are used as measures of energy. The Commission's current policy does not specify required analyses of capacity markets as such, likely because competitive conditions in the energy market in peak periods closely correlate with conditions in capacity markets. Nevertheless, I have analyzed the PJM Reliability Pricing Margin ("RPM") capacity market. ERCOT has no capacity market per se.

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

Order No. 642 directs applicants to analyze relevant ancillary services markets (specifically, reserves and imbalance energy) "when the necessary data are available." As discussed below, I analyzed relevant ancillary services markets.

Q. HOW HAS THE COMMISSION ANALYZED GEOGRAPHIC MARKETS?

A. Traditionally, the Commission has defined the relevant geographic markets as centered on the areas where applicants own generation and on the balancing authority areas directly interconnected with the applicants' generation. Both Order No. 592 and the Revised Filing Requirements continue to define the relevant geographic market in terms

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34 As I discuss below, evaluating Available Economic Capacity is quite difficult in PJM, given retail access and the separation of generation ownership and customer supply functions in Pennsylvania, New Jersey, Delaware, Maryland and Illinois. Even identifying Exelon's load commitments is difficult, given the status of both Illinois and Pennsylvania restructuring. It is virtually impossible to match generation and load commitments for most PJM utilities. However, given the mitigation commitments, the conclusion is easily reached that there is no competitive effect in PJM East. I address this in more detail below.

of destination markets.[35] Further, in a merger context, the Commission considers as potential additional destination markets other utilities that historically have been customers of the applicants.

This test is intended to be a conservative screen to determine whether further analysis of market power is necessary. If the Appendix A analysis shows that a company will not be able to exercise market power in its first-tier destination markets, it generally follows that the applicants will not have market power in more broadly defined and more geographically remote markets.[36] The screen is the first step in determining whether there is a need for further investigation. If the screening test is not passed, leaving open the issue of whether the merger will create market power, the Commission invites applicants to propose mitigation remedies targeted to reduce potential anti-competitive effects to safe harbor levels. In the alternative, the Commission will undertake a proceeding to determine whether unmitigated market power concerns mean that the merger is contrary to the public interest.

While destination markets typically are defined as individual balancing authority areas (previously, control areas), the Commission's practice has been to aggregate customers that have the same supply alternatives into a single destination market. This approach has been accepted in a number of merger filings in New York, PJM, and New England.[37] The Commission's indicative screens for purposes of determining eligibility to obtain

35 *Revised Filing Requirements*, Section 33.3(a)(2). "Identify each wholesale power sales customer or set of customers (destination market) affected by the proposed transaction. Affected customers are, at a minimum, those entities directly interconnected to any of the merging entities and entities that have purchased electricity at wholesale from any of the merging entities during the two years prior to the date of the application."

36 This same logic urges that if there is no adverse effect on competition in areas in which applicants control generation, there will be no effect on first-tier markets either. There may be exceptions to this rule: suppose that applicant A has significant generation in market I and applicant B has significant generation in market III, the two markets not being first-tier to each other. There nonetheless might be a competitive issue in market II, assumed to be first tier to both I and III. In analyzing this transaction we have considered this possibility and found no candidate markets where this is a potential issue.

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

authority to sell at market-based rates also uses balancing authority areas or the Regional Transmission Organizations ("RTOs") and Independent System Operators ("ISOs") as default geographic markets.[38] The Commission also has considered submarkets within RTOs/ISOs as separate geographic markets, including PJM East.[39]

As discussed in the summary and detailed below, in the context of this merger the appropriate focus of the competitive analysis is on the PJM East submarket, as well as ERCOT and two zones within ERCOT (Houston and North). As I will describe, the overlap of generation ownership in other geographic markets is *de minimis* and therefore does not require a screen analysis.

Vertical Market Power Issues

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

A. In the Revised Filing Requirements, the Commission set out several vertical issues potentially arising from mergers with input suppliers. The principal issue identified is whether the merger may create or enhance the ability of the merged firm to exercise market power in downstream electricity markets by control over the supply of inputs used by rival producers of electricity. Three potential abuses have been identified: the upstream firm acts to raise rivals' costs or foreclose them from the market in order to increase prices received by the downstream affiliate; the upstream firm acts to facilitate collusion among downstream firms; or transactions between vertical affiliates are used to frustrate regulatory oversight of the cost/price relationship of prices charged by the downstream electricity supplier.[40] The downstream products to be analyzed in a vertical analysis are the same as in the horizontal analysis.

38 *Order No. 697* at P 231.

39 *Id.* at P 246, citing to a number of Commission decisions involving electric utility mergers, including Exelon-PSEG.

40 While Order No. 642 identifies these three types of effects, the third is more properly an effect on rates and regulation, review criteria that exist separately from market power.

With respect to the vertical analysis, the Commission proposes defining the downstream geographic and product markets in the same manner as in the horizontal analysis. For upstream markets, the relevant geographic market has not been defined by the Commission. In concept, it should include the area in which suppliers to generators competing in the downstream market are located.

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

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

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

A. The Commission has expressed its concern in decisions addressing "convergence mergers" between electric utilities and natural gas pipelines and in Order No. 642, that vertical mergers "may create or enhance the incentive and/or ability for the merged firm to adversely affect prices and output in the downstream electricity market and to discourage entry by new generators."[41]

In addition to the three generic areas of vertical concern noted above, the Commission also has expressed concerns that (a) convergence mergers involving an upstream gas supplier serving the downstream merger partner, as well as competitors of that partner, could result in preferential terms of service; and (b) a pipeline serving electric generation could provide commercially valuable information to newly affiliated electricity generating or marketing operations.

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41 III FERC Stats. & Regs. Regs. Preambles, ¶ 31,111 at 31,904.

Finally, the Commission also has expressed the concern that an entity that control electric transmission could use that control to favor its own generation.

Q. HOW DOES THE COMMISSION DIRECT THAT VERTICAL MARKET POWER ISSUES BE ANALYZED?

A. The Commission has stated that a necessary condition for a convergence merger to cause a vertical concern is that both the upstream and downstream markets are highly concentrated.[42] In other words, the screen is passed if the downstream (or upstream) market is not highly concentrated, irrespective of the degree of concentration of the upstream (or downstream) market. A proper analysis of the upstream market requires that the structure of control of transportation capacity be examined, which requires that control of the transportation capacity be allocated to holders of firm capacity rights on the relevant pipelines with any unsubscribed capacity allocated to the pipeline owner. In my experience, this allocation has always resulted in a not highly concentrated market. In the context of this merger, which does not involve ownership of interstate natural gas pipelines *per se*, but merely control over shares of delivery capacity, a potential focus is on Exelon's and NRG's contractual rights to use the interstate pipeline delivery system into the relevant markets. Notwithstanding the analysis framework set forth in Order No. 642, merger applicants' contractual transportation rights have not been at the core of past vertical market power inquiries, and the Commission has recognized that open access gas

42 "[H]ighly concentrated upstream and downstream markets are necessary, but not sufficient, conditions for a vertical foreclosure strategy to be effective" Revised Filing Requirements, ¶ 31,311 at 31,911. "A vertical merger can create or enhance the incentive and ability of the merged firm to adversely affect electricity prices or output in the downstream market by raising rivals' input costs if market power could be exercised in both the upstream and downstream geographic markets." Order No. 642, *slip op*. at 79. This was confirmed in *Energy East*. ("Applicants correctly conclude that because they have shown that the downstream markets are not highly concentrated, there is no concern about foreclosure or raising rivals' costs in this case.") *Energy East Corporation and RGS Energy Group, Inc.*, 96 FERC ¶ 61,322 (2001) at p. 9.

pipeline regulations prevent sellers from withholding such capacity.[43] In any event, as noted above, the analysis I performed in the Exelon-PSEG merger case demonstrates clearly that the upstream gas market, structurally defined by firm pipeline rights, would not be highly concentrated after consummation of this transaction. Also potentially relevant is Exelon's control over a gas distribution system; I discuss this further below.

With respect to ownership of electric transmission facilities, the Commission in the past has focused on the extent to which the transmission owner provides open-access transmission or has transferred operational control over its transmission facilities to an ISO or an RTO.

43 As the Commission noted in *Order No. 697* in connection with market-based rate authority, "its open access regulations adequately prevent sellers from withholding interstate pipeline capacity. In addition, interstate pipeline capacity held by firm shippers that is not utilized or released is available from the pipeline on an interruptible basis." *Market-Based Rates for Wholesale Sales of Elec. Energy, Capacity and Ancillary Servs. by Pub. Utils.*, Order No. 697, FERC Stats. & Regs. ¶ 31,252, at P 430.

IV. DESCRIPTION OF METHODOLOGY

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

A. I evaluated the competitive effects of the merger using the delivered price test outlined in Appendix A and the Revised Filing Requirements. I implemented this analysis using a proprietary CRA model called the "Competitive Analysis Screening Model" ("CASm"). The source and methodology for the data required to conduct the delivered price test in CASm are described in Exhibit J-5. A technical description of CASm is provided in Exhibit J-6. As is appropriate for this transaction in which neither party controls significant upstream assets, the focus is on horizontal effects.[44]

Q. WHAT DESTINATION MARKETS DID YOU CONSIDER?

A. Consistent with the instructions in the Revised Filing Requirements, I identified the destination markets that could potentially be impacted by the merger. The first step in determining the potentially relevant markets is to identify where both Exelon and NRG owned or controlled generation. Table 1 below presents a summary of this information.

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44 Consistent with 18 C.F.R. § 33.4(a)(2), the merging entities "do not provide inputs to electricity products (*i.e.*, upstream relevant products) and electricity products (*i.e.*, downstream relevant products) in the same geographic markets" or "the extent of the business transactions in the same geographic market is *de minimis*."

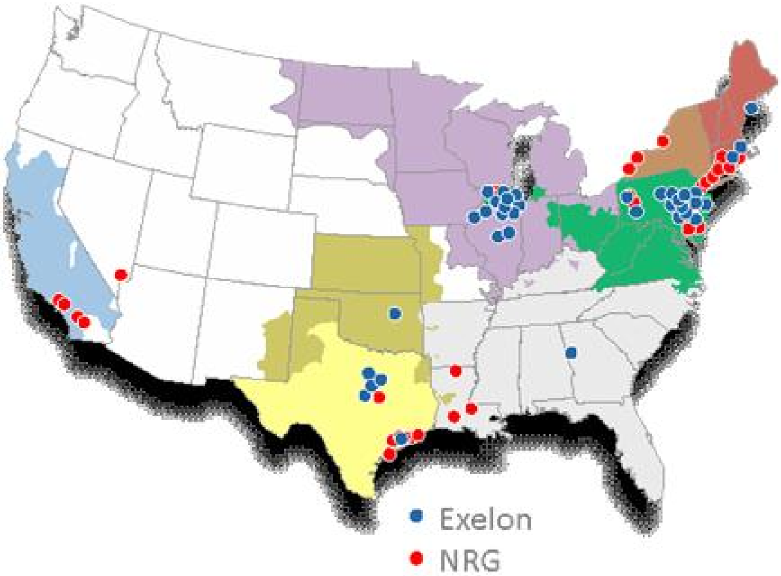
Table 1: Summary of Generation Owned by Exelon and NRG

Balancing Authority Area	Exelon	NRG
PJM	23,698	1,644
ISO-NE	178	2,204
NYISO	—	4,051
ERCOT	3,405	13,269
CAISO	—	2,633
MISO	1,043	—
NEVP	—	51
CSWS	795	—
EES/LAGN	853*	2,994
SOCO	933	—
Total	**30,052***	**26,847**

* The 853 MW connected to EES also is connected to ERCOT. The total removes the double count.

Figure 1 below provides a map of where the parties' generation is located.

Figure 1: Location of Exelon and NRG Generating Facilities in the United States



Based on the data in Table 1 (and the more detailed plant listing included in Exhibits J-3 and J-4), the following facts are evident with respect to potentially relevant geographic markets.

Exelon owns or controls generation in PJM, ERCOT, ISO-NE, MISO, and the CSWS, SOCO and EES balancing authority areas. NRG owns or controls generation in PJM, ERCOT, ISO-NE, NYISO, CAISO, and the NEVP and EES/LAGN balancing authority areas. As noted earlier, while LAGN is a separate balancing authority area, generation in LAGN used the transmission systems of transmission providers – primarily Entergy – to move generation to its customers. Generation in the LAGN balancing authority area is generally treated as part of the EES balancing authority.[45]

Thus, the markets in which both Exelon and NRG own or control generation include PJM, ERCOT, ISO-NE, and the EES (including LAGN) balancing authority area. Each of these markets is analyzed, along with submarkets as appropriate, as discussed below. I conducted a Competitive Analysis Screen for PJM and its relevant submarket, PJM East, as well as ERCOT, and its North and Houston zones.[46] While I believe that this is sufficient to demonstrate a lack of competitive effect in jurisdictional markets, in anticipation of possible contrary views, I also present analyses of other markets as discussed below.

Q. WHAT TIME PERIODS/LOAD CONDITIONS DID YOU ANALYZE?

A. For all markets for which full DPT analyses are performed, I examined ten time periods/load conditions. I used these 10 time periods for both the Economic Capacity and Available Economic Capacity measures. While the taxonomy is largely dictated by Commission policy and precedent, it is useful to recall that the origin of the DPT time periods is to provide a selection of snapshots that reflect a broad range of system conditions. Broadly, I evaluated hourly load data to aggregate similar hours. I defined periods within three seasons (Summer, Winter and Shoulder) to reflect the differences in unit availability, load and transmission capacity. Hours were first separated into seasons to reflect differences in generating availability and then further differentiated by load

45 *See*, for example, *Affidavit of Matthew E. Arenchild, PhD, On Behalf of Entergy Services Inc., et al*., Docket No. ER91-569-043 *et al.*, August 29, 2008, at note 10.

46 I did not conduct an Available Economic Capacity analysis for ERCOT, for the reasons described below.

levels during each season.[47] For each season, hours were segmented into peak- and off-peak periods.[48] The periods evaluated (and the designations used to refer to these periods in exhibits) are:

SUMMER (June-July-August)

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

WINTER (December-January-February)

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

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

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

I also present an analysis of installed capacity (using summer ratings) to demonstrate that the impact of the transaction is *de minimis* in markets where both Exelon and NRG own or control generation. This is essentially the same as doing an analysis of the summer super peak.

47 Appendix A requires applicants to evaluate the merger's impact on competition under different system conditions. For example, aggregating summer peak and shoulder peak conditions may mask important differences in unit availability and, therefore, a merger could potentially affect competition differently in these seasons. Thus, applicants are directed to evaluate enough sufficiently different conditions to show the merger's impact across a range of system conditions. On the other hand, the DOJ/FTC *Horizontal Merger Guidelines* discuss the ability to "sustain" a price increase, and a finding that a structural test (like the HHI statistic) violates the safe harbor for some small subset of hours during the year may not be indicative of any market power problems.

48 Peak and off-peak hours were defined according to NERC's definition, except that I did not consider Saturdays to be peak days. For the Eastern Time Zone, on-peak hours include Hour Ending (HE) 0800-HE 2300 EST Monday through Saturday and off-peak hours include HE 2400-HE 0700 EST Monday through Saturday. *See* http://www.nerc.com/files/opman_12-13Mar08.pdf.

Q. WHAT "COMPETITIVE" PRICE LEVELS DID YOU ANALYZE IN YOUR PJM ANALYSES?

A. For the PJM East destination market, I evaluated conditions assuming destination market prices ranging from $55/MWh in the Shoulder Off-Peak periods to $250/MWh in the Summer Super Peak period. In Order No. 642, the Commission indicated that sub-periods within a season should be determined by load levels rather than by time periods. As discussed below, I analyzed each market at prices that range from the levels that would apply at the lowest load levels to those consistent with the highest load levels. These prices analyzed were selected based on a review of market prices. I considered the frequency and distribution of market prices, irrespective of season, as well as the distribution of market prices based on the seasonal definitions used for modeling purposes. Different price levels were used for PJM as a whole in recognition that PJM East has higher prices than the RTO as a whole. For PJM, I used prices ranging from $45/MWh in shoulder off-peak to $250/MWh in summer super-peak, with the prices in other time periods somewhat lower than those in the PJM East analysis as shown on the summary tables and exhibits discussed below.[49] For PJM Classic, prices were generally between the assumed PJM East and PJM prices, except for the top price, which was $250/MWh in each of the markets. For ERCOT and its submarkets, I used prices ranging from $50/MWh in the shoulder off-peak to $250/MWh is the summer super-peak. These broad ranges of prices, in combination with the time periods, should be reflective of a sufficient range of system conditions such that a full effect of the merger is captured in the analysis. In addition, I conducted price sensitivity analyses around these base case prices, which evaluated somewhat higher and lower prices.[50]

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49 I took into consideration actual prices in relevant PJM markets during 2007-2008, fuel prices in 2007 and 2008 and forecast fuel and electricity prices for the reference year of my analysis, 2009. I largely relied on forecast price data from Ventyx, The Velocity Suite.

50 The results of these sensitivity analyses are provided in workpapers.

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

A. I used CRA's proprietary model, CASm, to perform the analysis. CASm is a linear programming model developed specifically to perform the calculations required in undertaking the delivered price test and has been used to provide analyses supporting scores of filings before the Commission. The model includes each potential supplier as a distinct "node" or area that is connected via a transportation (or "pipes") representation of the transmission network. Each link in the network has its own non-simultaneous limit and cost. Potential suppliers are allowed to use all economically and physically feasible links or paths to reach the destination market. In instances where more generation meets the economic element of the delivered price test (*e.g.*, 105 percent of the market price) than can actually be delivered on the transmission network, scarce transmission capacity is allocated based on the relative amount of economic generation that each party controls at a constrained interface.

Q. HOW DID YOU ALLOCATE LIMITED TRANSMISSION CAPACITY?

A. Appendix A notes that there are various methods for allocating transmission, and that applicants should support the method used.[51] I allocated transmission based on a prorata, "squeeze down" method based on relative ownership shares of capacity at a transmission interface, rather than on the basis of economics, which would allocate limited transmission first to the generation with the lowest variable costs. The prorata "squeeze-down" method, so-named because it seeks to prorate capacity at each node, is the closest approximation to what the Commission applied in *FirstEnergy*[52] *that is computationally*

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

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

feasible. Under this method, shares of available transmission are allocated at each interface, diluting the importance of distant capacity as it gets closer to the destination market. When there is economic supply (*i.e.*, having a delivered cost less than 105 percent of the destination market price) competing to get through a constrained transmission interface into a control area, the transmission capability is allocated to the suppliers in proportion to the amount of economic supply each supplier has outside the interface.

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

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

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

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

A. Analyzing the PJM and PJM East markets requires an assumption about simultaneous import limit ("SIL"). In my base case analysis, for imports into PJM, I used a SIL that PJM calculated recently in connection with market-based rate proceedings.[53] This is a SIL for a 2006 period, but should be broadly consistent with the SIL going-forward. Moreover, in the context of this merger, the precision of the SIL is less significant because (1) Exelon and NRG own relatively small shares of generation in markets first-tier to PJM (i.e., Exelon's Clinton plant in MISO and NRG's generation in NYISO) and areas adjacent to PJM East (i.e., PJM Central); and (2) the "clean sweep" mitigation approach limits the relevance of specific assumptions underlying the competitive screens themselves. I demonstrate the robustness of my results around a considerable range of assumptions for the SIL into PJM.

Similarly, for PJM East, for my base case analysis, I start with the SIL that PJM calculated in connection with market-based rate proceedings.[54] I also conducted an analysis based on data published by PJM on the hourly "Average Eastern Transfer

53 *PSEG Energy Res. & Trade LLC*, 124 FERC ¶ 61,147 (2008) ("PJM SIL Approval Order"). As noted in the order, the PJM SIL studies were filed on April 30, 2008 (for the PJM market) and July 14, 2008 (for the PJM East market).

54 *Id.* Note that as part of its SIL analysis for PJM East, PJM identified the specific units that it included within the PJM East submarket, and I followed PJM's convention for plants located in the East in my analysis.

Limit."[55] In the context of its market-based rate analysis, the Commission specifically allows the use of actual flows as a proxy for the SIL,[56] but since PJM calculates a limit in addition to the actual flows, the SIL is better approximated by the limit. Nevertheless, I conducted sensitivity analyses using both maximum hourly transfer limit by season as well as actual flows by season.[57] Since both the transfer limit and the actual flows reflect only transfers from within PJM, and not from external sources, I considered augmenting this intra-PJM transfer capability with a transfer capability from NYISO, which also is interconnected to PJM East. NYISO connects to PJM East from three sources: (i) about 2,000 MW import capability from zone G (Hudson Valley) that is used primarily to wheel power back into NYISO; (ii) an interconnection with zone J (New York City) that has zero import capability into PJM since it is reserved to export wheeled power into Zone J; and (iii) the 660 MW Neptune cable between New Jersey and Long Island (zone K), which for all practical purposes is reserved by the Long Island Power Authority under a 20 year agreement with Neptune for delivery from PJM to Long Island, leaving available capacity into PJM at zero.[58] See Figure 2 below.[59] Hence, there is little if any ability to deliver power directly from NYISO into PJM East. Nevertheless, I modeled NYISO to PJM imports in a manner consistent with the transmission capacity assumptions underlying the figure, with the exception of the Neptune cable linking Long Island which I did not include as providing import capacity into PJM.[60] This means that NRG generation in NYISO outside of zone J is allowed to access PJM East via its allocable share of the link from zone G, or by entering PJM Central and West and competing for transmission within PJM into PJM East.

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55 http://www.pjm.com/services/system-performance/downloads/flows/2007-flows.xls and http://www.pjm.com/services/system-performance/downloads/flows/2008-flows.xls.

56 *Order No. 697* at P 354 n.358.

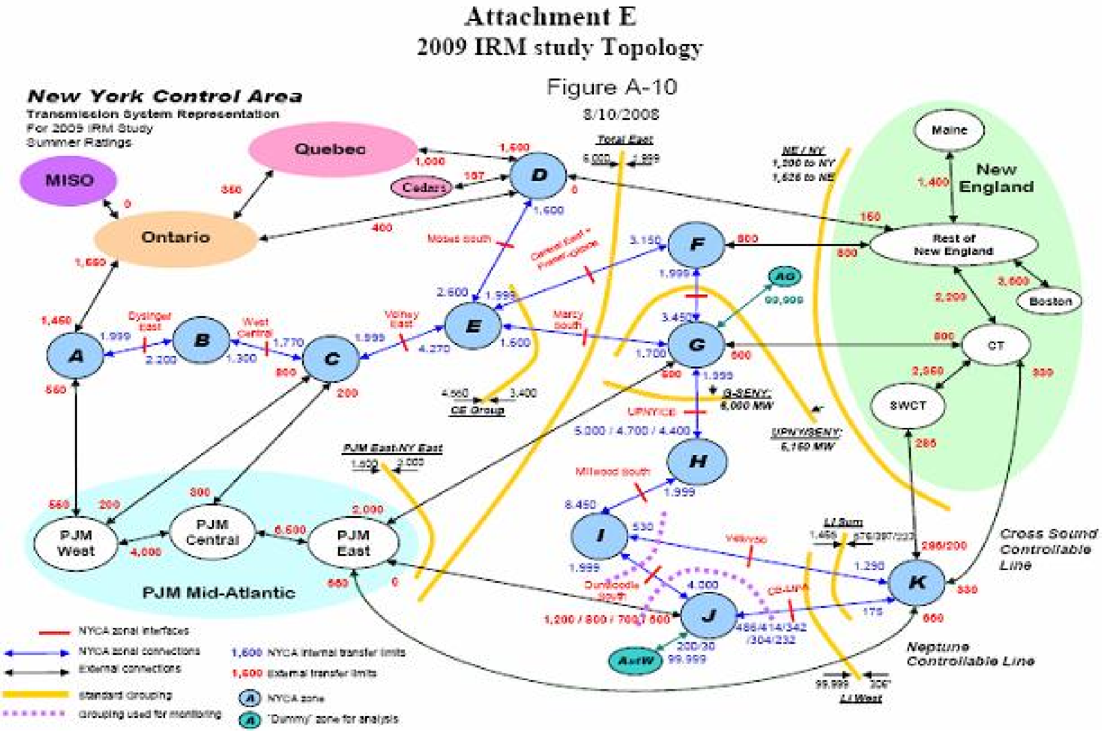
57 The actual maximum seasonal flows were 91-94 percent of the maximum limits in 2006.

58 http://www.lipower.org/newscenter/pr/2007/062807_neptune.html

59 http://www.nysrc.org/pdf/Reports/2009%20IRM_Assumption_Matrix_Final.pdf

60 I include in my workpapers a sensitivity analysis that allows imports on the zone G to PJM East path, and includes the Neptune cable as exporting to PJM.

Figure 2: Transmission Map of Assumptions for 2009-2010 New York IRM Requirement Study



The actual limitations on use of the NYISO to PJM East transmission also is relevant to analysis of the effect of this transaction both in PJM East and in NYISO. NRG's generation in NYISO is not directly importable into PJM East, and its generation in zones A and C can access PJM East primarily through PJM Central or West (due to the use of the Zone G interconnection to wheel power through PJM to New York City) and across the PJM transfer limit into PJM East.[61] Exelon generation in PJM East can only be delivered into NYISO via connections in PJM Central and West into upstate New York.

61 Figure 2 provides some insight, but an incomplete picture, of the transfer capability between PJM East and New York. In addition to the Neptune DC line discussed previously, it shows a connection between PJM East and NYISO Zone G (up to 600 MW into G and 2,000 into PJM East), and between PJM East and Zone J (up to 1,200 MW into J and zero into PJM East). Superficially, this would seem to imply that up to 1,800 MW could flow from PJM East into NYISO, such that Exelon's presence in that market theoretically might not be *de minimis*. In reality, there is essentially no capability to use these two connections to export PJM East generation into NYISO. Collectively, they comprise the "Farragut Wheel", a transmission path used to bypass a constrained interface in NYISO (Dunwoodie South) to bring power into Zone J (New York City). Hence, the path between NYISO Zone G and PJM East is loaded to bring power from NYISO into PJM and the path between PJM East and Zone J is loaded into Zone J to wheel this same power into the City. Because the path between PJM East and Zone J is reserved to transfer power into Zone J and the path between Zone G and PJM East is reserved for power that wheels back into NYISO, there also is essentially no ability for NRG generation in NYISO to compete in the PJM East market.

When I analyzed the PJM East market, I assumed that generation in the rest of PJM competed for the limited transmission. In other words, I did not “squeeze” generation from Far West to West to Central. This is consistent with the assumption that, although PJM East is a sometimes-constrained market, the remaining interfaces in PJM are not often constrained or constrained at the same time as PJM East. More importantly for present purposes, this assumption is quite conservative in that it treats Exelon-controlled generation in Illinois equally with generation in portions of PJM far closer to the PJM East market.

Q. DID YOU EXAMINE ANY OTHER SUB-MARKETS WITHIN PJM?

A. Yes. Because of the West-to-East power flows within PJM, it has been traditional to examine cascading sub-markets within the Mid-Atlantic part of PJM (also referred to as pre-expansion or “Classic” PJM). Thus, in past transactions, I have examined sub-markets consisting of PJM East, PJM Central-plus-East and PJM West-plus-Central-plus-East, all of these being sub-areas within PJM Mid-Atlantic. Because NRG owns no generation in either PJM West or Central, this analysis would provide no additional insight to that informed by the PJM East analysis, since adding the other areas would serve only to dilute the combined Exelon and NRG market shares relative to the PJM East analysis.

While NRG owns essentially no generation in either West or Central,[62] it does own a 127 MW share of Keystone and Conemaugh located in an area traditionally termed “PJM Far-West”. PJM Far-West is not a sub-market of any economic or electrical significance, nor is a cascading market consisting of “PJM Far-West-plus-West-plus-Central-plus-East”. Rather, PJM Far-West is merely the rump portion of PJM Classic that was west of the

62 The 12 MW Paxton Creek Cogeneration facility owned by NRG is located in Harrisburg, PA.

first meaningful West-to-East constraint in PJM Classic, the West interface. The only generation within this portion of PJM is Keystone and Conemaugh. Because there are no transmission constraints that meaningfully separate PJM Far-West from areas to the west of it (e.g., AEP), there is no logic for an analysis that includes PJM Far-West in a sub-market but excludes areas further to the west.

I am nonetheless aware that some parties in the past have analyzed a PJM Classic (Mid-Atlantic) market. While I disagree for the reasons I have discussed, I have performed an economic capacity analysis of this market to demonstrate the absence of screen failures.

I also considered the effect of the transaction on Northern Illinois, where Exelon owns generation and NRG owns a single generating station (Rockford, a 447 MW peaking station). I am not suggesting that Northern Illinois is a relevant geographic market, but I nevertheless provide the pertinent facts to demonstrate that there is no adverse competitive effect in this area.

Q. WHAT MARKETS OUTSIDE OF PJM DID YOU ANALYZE?

A. In view of the fact that both Exelon and NRG own generation in ERCOT, I performed an economic capacity analysis of ERCOT and the two zones within it, ERCOT North and Houston, where Exelon and NRG both own generation. I recognize that ERCOT is non-jurisdictional to the Commission for most or all purposes, but have included the analysis against the possibility of a party arguing that an analysis that did not look at ERCOT markets would be deficient. Of course, the “clean sweep” approach to mitigation of market power issues within ERCOT makes an analysis of pre-mitigation market structure changes relatively meaningless. It does serve the purpose of providing information concerning the extent to which regulators might be concerned about interim mitigation before Exelon’s generation and contracts can be divested. I did not perform an available economic capacity analysis of ERCOT because there is full retail access and most generation is severed from retail load service.

Because ERCOT is interconnected to the Eastern Interconnection, albeit quite weakly, there is a theoretical possibility that enough NRG generation in ERCOT would be allocated tie capacity sufficient to cause screen failures in adjacent jurisdictional markets in which Exelon controls generation. Both of the relevant ties, the North Tie and the East Tie, connect to the CSWS balancing area, an area in which Exelon has a modest amount of generation under a long-term contractual arrangement. In order to demonstrate that this theoretical problem is not real, I prepared a full Economic Capacity and Available Economic Capacity DPT for the CSWS balancing area.

With the exception of the CSWS balancing area, I prepared no analyses of markets in which only one of the entities has capacity. For those markets where the market shares of one or both of the entities is quite small, I demonstrate that the extent of business transactions in the same market is *de minimis* by performing a HHI analysis of installed capacity, equivalent to a DPT during the summer super-peak period. These analyses demonstrate the *de minimis* nature of the overlap and the lack of competitive effect.[63]

Q. WHAT YEAR DID YOUR ANALYSIS COVER?

A. I analyze 2009 market conditions, consistent with the Order No. 642 requirement that the analysis be forward looking.

Even though my analysis approximates 2009 market conditions, the primary source of data on generation and transmission is current and recent historical data. Where appropriate, I adjusted relevant data to approximate 2009 conditions. As described in Exhibit J-5, this includes load and generation dispatch (*i.e.*, fuel and other variable) costs. With respect to new generation, I only included generation already under construction and expected to be on-line by 2009; I did not include any additional planned generation

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63 As explained elsewhere, because Exelon's remaining ISO-NE generation is old and inefficient and has very low capacity factors, an installed capacity analysis captures the extent of competition in those time periods and product categories in which Exelon's generation is likely to compete. Neither entity's participation in the EES balancing area is *de minimis*, though their shares are relatively small. For this market, the purpose of the installed capacity analysis is to demonstrate that the "clean sweep" of Exelon's generation in ERCOT also eliminates its presence in EES, given that the only generation Exelon owns or controls in EES is the Frontier facility that is also interconnected to ERCOT and hence part of the ERCOT clean sweep.

not yet under construction. With respect to retirements, I included only units already retired or already approved by PJM for retirement for retirement by 2009. I also treated Exelon's mothballed generation in ERCOT (190 MW) for which retirement is planned prior to closing this transaction as being retired.

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

A. In the past, I have treated long-term power arrangements as resulting in a transfer of ownership and control to the purchaser, but the Commission's current policy appears to favor assigning control to the contractual party with dispatch rights. [64] For most purchases and sales, I am unable to determine whether the seller or buyer has control[65] and in those cases I assigned control to the buyer. I note, however, that the treatment of purchases and sales is inconsequential in terms of the results of my analysis, except with respect to Exelon's and NRG's contracts. As described below, I have assumed, as appropriate, that contracts transferring control to Exelon and NRG are treated as such.

Exelon Generation has several long-term (more than one-year) contracts to purchase the output of various plants located in the former ComEd control area. Through February 2013, Exelon Generation has contracts with affiliates of Dominion to purchase the output

64 *Revised Filing Requirements*, Section 33.3(c)(4)(i)(A).

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

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

of the Kincaid coal-fired plant located in Illinois. In my analysis, I treated the entire output of this facility as available to (and controlled by) Exelon Generation when economic. Exelon Generation has two additional long-term PPAs that continue past 2009 for approximately 1,300 MW of supply from merchant generation (peakers), located in the former ComEd control area, that I also treated as under Exelon's control.[66]

With respect to purchases from QFs or non-utility generators ("NUGs"), I included as Exelon-affiliated generation its purchases from QFs and small non-utility generators (cumulatively totaling less than 200 MW) and treated them as must-take, non-dispatchable and hence economic in all time periods.

As described previously, Exelon has PPAs to purchase generation at the Wolf Hollow and Frontier stations in Texas and a PPA to sell output from Frontier to EES. I treated the PPAs to buy output from these two facilities as transferring control to Exelon, but did not assume that the PPA with EES transferred control of 300 MW away from Exelon. In CSWS, Exelon has a tolling agreement with respect to the Green Country facility, which I treated as giving Exelon control.

I am not aware of any long-term PPAs that NRG has that might convey control, other than a 600 MW tolling agreement in the EES balancing authority, which is reflected in Exhibit J-4 as under NRG's control.

66 Exhibit J-3 also reflects other long-term PPAs or tolling agreements outside of PJM that are assumed to give Exelon Generation control for the output of generation.

V. IMPACT OF THE MERGER ON COMPETITION

PJM

Q. WHAT PJM MARKETS DID YOU ANALYZE?

A. I examined a PJM RTO-wide market, as well as the PJM East and PJM Classic submarkets, where both Exelon and NRG own generation. As noted earlier, the Commission has deemed PJM East a relevant submarket in past transactions as well as in the context of its market-based rate screens.[67] The location of Exelon's and NRG's generation in PJM is summarized in Table 2 below:

Table 2: Exelon and NRG Generation in PJM

	Exelon (MW)	NRG (MW)
PJM East	8,454	1,058
PJM Classic	2,612	139
PJM Midwest (Illinois)	12,633	447
Total PJM	23,698	1,644

Exelon owns or controls approximately 8,400 MW of generation in PJM East, and NRG owns 1,058 MW in PJM East, consisting of Dover Energy (104 MW), Vienna (158 MW), and Indian River (796 MW). As I noted earlier, two of the Indian River units (176 MW) are scheduled to be retired in 2010 and 2011.

Outside of PJM East, the generation owned by NRG in PJM is located in western Pennsylvania (139 MW) and Illinois (447 MW). Exelon owns or controls about 15,000 MW of generation in PJM outside of PJM East, mostly in Illinois (approximately 12,600 MW) and the remainder in the original PJM footprint (approximately 2,600 MW). Exelon and NRG are each (minority) joint owners in the Keystone and Conemaugh, two large coal-fired stations in far western Pennsylvania that have a total generating capacity of approximately 3,400 MW. Exelon's share of the two generating stations is just under 21 percent, and NRG's share is about 3.7 percent. The units are operated and bid into the market by Reliant Energy Northeast Management Company but are deemed for purposes of this analysis to be controlled by Exelon and NRG for their respective shares.

67 *Order No. 697* at P 246, citing to *Exelon Corp*., 112 FERC ¶ 61,011 (2005) at P 122.

Q. WHAT SPECIFIC ANALYSES DID YOU CONDUCT IN PJM?

A. Consistent with the guidance in the *Merger Policy Statement*, for the PJM and PJM East markets, I analyzed Economic Capacity and Available Economic Capacity. I also analyzed Economic Capacity for the PJM Classic market for the sole purpose of assessing the impact of including Exelon's and NRG's shares of Keystone and Conemaugh with their shares in PJM East. I also address PJM's RPM capacity market and relevant ancillary services markets. Finally, while I do not find that northern Illinois is a separate relevant market, and therefore do not conduct a DPT analysis for that area, I analyze market facts to evaluate the competitive effect of combining Exelon's and NRG's generation in northern Illinois.

Economic Capacity

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

A. The Economic Capacity analysis reflects the relatively modest impact of the transaction in PJM. While Exelon's pre-merger share ranges from about 14 to 17 percent, NRG's share is no more than about one percent. The market is unconcentrated except in the summer and shoulder off-peak periods when it is barely into the moderately concentrated zone,[68] and the HHI change is no more than 34 points, as shown in Table 3 below and in Exhibit J-7. Thus, the Competitive Analysis Screen is easily passed in all time periods.

68 This is broadly consistent with the PJM's finding that the 2007 energy market had hourly HHIs ranging from 879 to 1525, with an average of 1205. *See 2007 State of the Market Report*, PJM Market Monitoring Unit ("*2007 PJM SOM Report*"), March 11, 2008, Vol. II, page 17. http://www.pjm.com/markets/market-monitor/som.html. Systematic differences between hourly HHIs based on bidding and DPT period average capability HHIs are inevitable, particularly since actual bids reflect unit inflexibility that will cause some units to run when they are uneconomic at that hour's price and others to not be available to run in hours when they would seem to be economic.

Table 3: Economic Capacity, PJM (pre-mitigation)

		Pre-Merger						Post-Merger (Pre-Mitigation)			
		Exelon		NRG							
Period	Price	MW	Mkt Share	MW	Mkt Share	Market Size	HHI	MW	Mkt Share	HHI	HHI Chg
S_SP1	$250	23,961	14.5%	1,604	1.0%	165,368	790	25,565	15.5%	818	28
S_SP2	$160	23,197	14.4%	1,602	1.0%	161,314	798	24,799	15.4%	827	29
S_P	$ 90	21,669	14.3%	1,413	0.9%	151,602	817	23,082	15.2%	843	27
S_OP	$ 50	18,051	15.7%	999	0.9%	114,772	1,009	19,050	16.6%	1,036	27
W_SP	$105	21,460	14.1%	1,327	0.9%	151,769	765	22,788	15.0%	790	25
W_P	$ 75	18,841	14.2%	1,283	1.0%	132,677	811	20,124	15.2%	839	27
W_OP	$ 50	16,608	15.5%	896	0.8%	107,527	908	17,504	16.3%	933	26
SH_SP	$100	19,774	14.7%	1,227	0.9%	134,551	820	21,002	15.6%	847	27
SH_P	$ 70	15,903	14.5%	1,211	1.1%	109,931	905	17,114	15.6%	937	32
SH_OP	$ 45	15,463	17.4%	854	1.0%	88,781	1,062	16,317	18.4%	1,095	34

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

A. In this market, the Competitive Analysis Screen is passed in all time periods, as shown below in Table 4 and in Exhibit J-7. Pre-Merger, Exelon's market share ranges from about 12 to 14 percent, and NRG's is less than 2 percent. The market is unconcentrated post-merger, and the HHI changes are at most 46.

Table 4: Economic Capacity, PJM Classic (pre-mitigation)

		Pre-Merger						Post-Merger (Pre-Mitigation)			
		Exelon		NRG							
Period	Price	MW	Mkt Share	MW	Mkt Share	Market Size	HHI	MW	Mkt Share	HHI	HHI Chg
S_SP1	$250	11,094	13.6%	1,349	1.7%	81,473	807	12,443	15.3%	852	45
S_SP2	$200	11,094	13.6%	1,350	1.7%	81,345	808	12,444	15.3%	853	45
S_P	$100	8,804	12.3%	1,176	1.7%	71,449	775	9,980	14.0%	816	41
S_OP	$ 55	7,699	13.0%	1,053	1.8%	59,093	803	8,752	14.8%	850	46
W_SP	$115	9,454	13.4%	1,041	1.5%	70,806	788	10,495	14.8%	827	39
W_P	$ 85	7,911	12.4%	928	1.5%	63,759	781	8,839	13.9%	818	36
W_OP	$ 60	6,987	12.4%	922	1.6%	56,289	788	7,908	14.1%	828	41
SH_SP	$105	8,987	13.6%	1,006	1.5%	66,322	776	9,994	15.1%	817	41
SH_P	$ 80	7,101	12.2%	897	1.5%	58,365	767	7,998	13.7%	804	37
SH_OP	$ 55	6,719	13.0%	904	1.8%	51,694	756	7,623	14.8%	801	45

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

A. This Economic Capacity analysis reflects the somewhat more significant overlap of generation owned by Exelon and NRG in PJM East.[69] In this market, the Competitive Analysis Screen is failed in three time periods, as shown below in Table 5 and in Exhibit J-7. Pre-Merger, Exelon's market share ranges from about 18 to 21 percent, and NRG's from 2 to 3 percent. The market is generally at the low end of the moderately concentrated range post-merger (and pre-mitigation), and HHI changes are in excess of 100 points in two off-peak periods (one of which is an unconcentrated market as well as in the two summer super peak periods, although in all these periods the HHI change is just slightly over 100. Thus, there is a slight screen failure in one off peak period and a slight screen failure in the summer super peak periods. While such very slight, non-systematic screen failures do not indicate that the transaction will create a market power issue in PJM East, Exelon has proposed clean sweep mitigation to assure that the issue is mooted.

Table 5: Economic Capacity, PJM East (pre-mitigation)

		Pre-Merger						Post-Merger (Pre-Mitigation)			
		Exelon		NRG							
Period	Price	MW	Mkt Share	MW	Mkt Share	Market Size	HHI	MW	Mkt Share	HHI	HHI Chg
S_SP1	$250	9,296	20.8%	1,116	2.5%	44,711	1,088	10,411	23.3%	1,192	104
S_SP2	$200	9,298	20.8%	1,116	2.5%	44,647	1,090	10,414	23.3%	1,194	104
S_P	$100	7,065	18.5%	948	2.5%	38,131	955	8,012	21.0%	1,047	92
S_OP	$ 60	6,033	18.7%	910	2.8%	32,273	930	6,944	21.5%	1,036	105
W_SP	$120	7,908	20.2%	845	2.2%	39,067	1,012	8,753	22.4%	1,099	88
W_P	$ 90	6,573	18.3%	834	2.3%	35,856	940	7,407	20.7%	1,025	85
W_OP	$ 65	5,554	17.9%	811	2.6%	31,029	883	6,365	20.5%	977	94
SH_SP	$110	7,716	20.5%	823	2.2%	37,578	975	8,539	22.7%	1,064	90
SH_P	$ 80	5,908	17.6%	813	2.4%	33,513	880	6,721	20.1%	965	86
SH_OP	$ 55	5,522	19.1%	803	2.8%	28,924	867	6,326	21.9%	973	106

69 The analyses also reflect the allocation of a portion of the interface into PJM East to generation located in the rest of PJM and NYISO.

Q. GIVEN EXELON'S "CLEAN SWEEP" MITIGATION COMMITMENT IN PJM EAST, WHAT ARE THE POST-MITIGATION RESULTS FOR PJM EAST?

A. The mitigation completely cures the screen failures in PJM East (and similarly would improve the results for the PJM market and PJM Classic market). The exact numerical results post-mitigation depend on the parties that ultimately acquire NRG's capacity in PJM East. Exhibit J-8 and Table 6 below shows the numerical result if all of NRG's capacity in PJM East was theoretically sold to a hypothetical single, new entrant into PJM. The small HHI changes that remain are traceable to import capability assigned to NRG's generation outside of PJM East.

Table 6: Economic Capacity, PJM East (post-mitigation)

		Pre-Merger						Post-Merger (Post-Mitigation)			
		Exelon		NRG							
Period	Price	MW	Mkt Share	MW	Mkt Share	Market Size	HHI	MW	Mkt Share	HHI	HHI Chg
S_SP1	$250	9,296	20.8%	1,116	2.5%	44,711	1,088	9,403	21.0%	1,097	9
S_SP2	$200	9,298	20.8%	1,116	2.5%	44,647	1,090	9,406	21.1%	1,099	9
S_P	$100	7,065	18.5%	948	2.5%	38,131	955	7,165	18.8%	963	8
S_OP	$ 60	6,033	18.7%	910	2.8%	32,273	930	6,097	18.9%	937	7
W_SP	$120	7,908	20.2%	845	2.2%	39,067	1,012	8,001	20.5%	1,021	9
W_P	$ 90	6,573	18.3%	834	2.3%	35,856	940	6,655	18.6%	948	8
W_OP	$ 65	5,554	17.9%	811	2.6%	31,029	883	5,613	18.1%	889	6
SH_SP	$110	7,716	20.5%	823	2.2%	37,578	975	7,821	20.8%	986	11
SH_P	$ 80	5,908	17.6%	813	2.4%	33,513	880	6,003	17.9%	889	9
SH_OP	$ 55	5,522	19.1%	803	2.8%	28,924	867	5,608	19.4%	877	10

Available Economic Capacity

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

A. Yes, although, as discussed earlier, developing an Available Economic Capacity analysis is quite difficult, given the status of retail access in PJM. Under conditions of full retail access, the Available Economic Capacity analysis becomes identical to Economic Capacity. However, despite retail access in some portions of PJM (*e.g.*, Pennsylvania, New Jersey, Maryland, Delaware, Ohio and Illinois), some utilities continue to have Provider Of Last Resort ("POLR") responsibilities. There also are parts of PJM where there is little if any scope for retail access. The primary analytic difficulty arises because there are no publicly available data identifying which generation is committed to serving load. In the case of integrated utilities having little retail access (e.g., AEP), it is straight-forward and consistent with the Merger Policy Statement to assume that load is served from the "bottom of the stack" of their own resources. In the case of the state auctions relevant to PJM East (most notably the New Jersey BGS auction, but also other auctions that may come to exist as transitional arrangements end over the next few years), the winning bidders include marketers who do not own generation. While it is very likely that most of the load served by sellers who lack generation is hedged with suitably long term contracts, it is impossible to determine from available data which generation the winning bidders have procured to serve the load, for what period or whether the terms of the contracts cause control to pass from the owner to the load serving entity. A further complication is that some of the retail load commitments that will be in effect in 2009 and beyond (including PECO's) will be determined in procurements that have not yet occurred.[70]

In any event, Available Economic Capacity is a questionable metric for defining market share in PJM. All capacity must be bid into the PJM market and selected to run before it can generate. Hence, irrespective of retail load commitments, all of a supplier's Economic Capacity is bid or scheduled into the real time (and most of it in day ahead) auctions and is relevant to setting market prices.

Notwithstanding these difficulties, and the fact that the clean sweep mitigation, by definition, means that Exelon will have no more Available Economic Capacity relating to generation located in PJM East than it would pre-Transaction, I developed a set of assumptions that allows an analysis of Available Economic Capacity.

First, I assumed that AEP and Virginia Power continue to have full load-serving responsibilities and use their lowest cost generation to meet load. I assume that Allegheny will have a similar load serving responsibility for 65 percent of its load.

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70 While Exelon Generation will continue to serve all of PECO's retail load through the 2009 period used in this analysis, I have assumed this fact away in order to market the analysis relevant also to periods subsequent to the end of transitional arrangements. As described below, the implicit assumption that I make concerning post-transition arrangements in Pennsylvania is that there will be an auction process similar to the BGS process in New Jersey and the initial auction process in Illinois.

Second, I assumed that New Jersey BGS, Maryland SOS and Delaware auctioned load will continue to be served by the parties that won recent auctions and if they are generation owners, that they would serve load using their own generation. Based on a review of recent results, this means that approximately 65 percent of these loads are met by dedicated resources. As with the AEP, Virginia Power and Allegheny loads, I assume that these generation-owning parties that had been successful bidders in the auctions in past auctions, serve the tranches they had won, with their lowest-cost owned generation. Third, I assumed that the two Exelon load-serving companies, PECO and ComEd, and PPL, whose transitional arrangements in Pennsylvania also are due to expire, each had 65 percent of their total loads served by the lowest-cost generation not otherwise committed as with the loads served under existing auctions in New Jersey, Maryland and Delaware. Consistent with the rules for and results of the Illinois auction, I assume that Exelon's share is limited to 35 percent and will be met by its local (PJM East, in the case of PECO) generation. I assume similarly that PPL's share of its generation committed to serving its load will be limited to 35 percent. The remainder of the load assumed to be served by dedicated generation (30 percent) is assumed to be served by the lowest cost generation that is not committed to serving other loads. The generation used to meet this tranche of load is assumed to be contracted in a fashion that removes it from the available capacity stack. The remainder of load, essentially 35 percent of PJM loads other than those of AEP and Virginia Power, is assumed to be met by available economic capacity (i.e., the generation that serves it is part of Available Economic Capacity). This is, of course, only one of many plausible scenarios determining what generation will be part of Available Economic capacity, but it is intended to be a reasonable and unbiased method of making that allocation. Under this scenario about 80 percent of total PJM load was assumed to have generation committed to serving it in an Available Economic Capacity sense. The equivalent share for PJM East load was about 68 percent.

Table 7: Available Economic Capacity, PJM East (pre-mitigation)

		Pre-Merger						Post-Merger (Pre-Mitigation)			
		Exelon		NRG							
Period	Price	MW	Mkt Share	MW	Mkt Share	Market Size	HHI	MW	Mkt Share	HHI	HHI Chg
S_SP1	$250	2,555	13.9%	438	2.4%	18,429	576	2,993	16.2%	642	66
S_SP2	$200	3,596	17.6%	398	1.9%	20,457	657	3,994	19.5%	725	68
S_P	$100	1,403	7.4%	198	1.0%	18,978	500	1,601	8.4%	516	15
S_OP	$ 60	374	2.2%	59	0.3%	17,220	535	433	2.5%	537	1
W_SP	$120	2,536	13.9%	194	1.1%	18,230	598	2,730	15.0%	627	30
W_P	$ 90	1,271	7.1%	171	1.0%	17,925	481	1,442	8.0%	495	14
W_OP	$ 65	364	2.3%	65	0.4%	15,890	455	430	2.7%	456	2
SH_SP	$110	2,600	15.0%	245	1.4%	17,391	593	2,845	16.4%	635	42
SH_P	$ 80	1,120	6.5%	147	0.9%	17,343	465	1,267	7.3%	476	11
SH_OP	$ 55	396	2.5%	75	0.5%	15,716	513	471	3.0%	515	2

As shown in Table 7 and Exhibit J-9, the PJM East Available Economic Capacity market is unconcentrated and the change in HHIs (pre-mitigation) is well less than 100 points. The primary reason for the unconcentrated nature of the market is that the large generation owners: 1) in many cases have explicit load requirements and 2) disproportionately own the lowest cost generation that is assumed to be contracted to serve parts of the 65 percent of load assumed to be met by self-generation or committed contracts. This result is not dissimilar to Available Economic Capacity analyses in areas where utilities remain vertically integrated: the fact that non-utility generators have higher shares of Available Economic Capacity than their shares of Economic Capacity generally often makes the Available Economic Capacity market substantially less concentrated.

In any event, given Exelon's "clean sweep" commitment, which includes selling all of NRG's generation located in PJM East, any impact of the transaction on Available Economic Capacity in PJM East will be neutralized, and the post-divestiture increase in Exelon's owned generation in PJM as a whole (less than 600 MW) is too small (in an Available Economic Capacity market that is about 10 percent of the 165,000 MW of installed capacity) to have a material effect on market concentration.

Northern Illinois

Q. YOU INDICATED EARLIER THAT YOU ALSO CONSIDERED THE IMPACT OF THE TRANSACTION IN NORTHERN ILLINOIS. WHAT DID YOUR ANALYSIS SHOW?

A. The first thing to note is that there is no basis for assuming that Illinois, or Northern Illinois is a relevant geographic market, separate from other parts of western PJM or nearby parts of MISO. Nevertheless, because NRG owns 447 MW of generation in Northern Illinois, where Exelon also owns or controls generation about 12,600 MW of generation, I considered whether the Transaction could have an impact in this region.

Because the only generation NRG owns in Northern Illinois is a peaking station, the only potential impact of the Transaction occurs when peaking units are economic, which is not often. Peakers in Northern Illinois had an annual capacity factor of only about 2 percent over the recent twelve month period (October 2007-September 2008), and in any given time period/load condition (based on the time periods I use in the DPT analysis) was no more than 6 percent. During the most recent twelve month data period, one or more of the Rockford units ran in only 302 of the 8784 hours.

There are 4,000 MW of peaking capacity of similar vintage to NRG's Rockford station in the PJM portion of Illinois that are not controlled by Exelon (in addition to Exelon's approximately 1,500 MW of peakers it owns or controls), as well as more than 4,000 MW of similar vintage peakers in the remainder of the western portion of PJM (i.e., in the AEP and Dayton sub areas). There also is similar capacity in the MISO portion of Illinois. On average, there was more than 3,500 MW of the 4,000 MW of competing peaking generation in Northern Illinois that was not running during hours when some portion of the Rockford station was operating. During the hours when one of the Rockford units was operating, the amount of competing peaking generation (excluding Exelon's) that was not producing energy was never less than 1,221 MW. Hence, there was idle competing generation sufficient to replace the output of Rockport several times over. Stated otherwise, Rockport is never pivotal or even nearly so. Based on these facts, there clearly is no adverse effect of the Transaction in Northern Illinois.

Capacity and Ancillary Services Markets

Q. WHAT DID YOUR ANALYSIS OF PJM CAPACITY MARKETS SHOW?

A. My analysis demonstrates that there are no competitive concerns raised in PJM capacity markets.

On June 1, 2007, the Reliability Pricing Model ("RPM") Capacity Market was implemented in PJM. In addition to an RTO-wide market, there also are local deliverability area ("LDA") markets, namely Eastern Mid-Atlantic Area Council ("EMAAC"), Southwestern Mid-Atlantic Area Council ("SWMAAC") and Mid-Atlantic Area Council plus APS ("MAAC+APS"). In the context of this transaction, the potentially relevant markets are the RTO, EMAAC, and MAAC+APS.[71] While the size of these markets, and the respective market shares of Exelon and NRG, is approximated by the summer super peak calculations in the DPT, I also conducted an analysis based on PJM's reported unforced capacity for these markets for the already-completed 2009-2010 auction.[72]

As shown in Table 8 below, the amount of unforced capacity in PJM as of June 1, 2009 was 157,318 MW. The table, as well as the two subsequent tables, reflects Exelon's and NRG's installed capacity (i.e., not reduced for forced outages), and even with this conservative measure, their combined shares, pre-mitigation, are only 16 percent, and the HHI change is only 32 points. Post-mitigation, Exelon's share is 15 percent, and the HHI change is about 11 points, reflecting acquired generation outside of PJM East.[73]

71 *Analysis of the 2009 – 2010 RPM Auction*, PJM Market Monitoring Unit, February 11, 2008. http://www.pjm.com/markets/market-monitor/downloads/mmu-presentations/20092010-rpm-review.pdf.

72 For 2009-10, in the 2009/2010 RPM Auction, EMAAC was not constrained. As a result, no results are reported, and the 2008-09 data are substituted. *2007 PJM SOM Report*, Vol. II, p. 248.

73 As with the energy market analysis the post-mitigation HHI change assumes a single, new entrant buys the divested generation.

Table 8: Effect of the Transaction in PJM UCAP Market, as of 6/1/09

	Pre-Transaction		Post-Mitigation	
	MW	Share	MW	Share
Exelon	23,698	15.06%	24,284	15.44%
NRG	1,644	1.05%	0	0.00%
Other	131,976	83.89%	133,034	84.56%
Total	157,318	100.00%	157,318	100.00%

Pre-Mitigation HHI Change: 32 HHI Change: 11

As shown in Table 9 below, the amount of unforced capacity in PJM East (EMAAC) as of June 1, 2008 was 31,379 MW. While the HHI change pre-mitigation exceeds 200 points, the clean sweep mitigation results in an HHI change of zero.[74]

Table 9: Effect of the Transaction in EMAAC UCAP Market, as of 6/1/08

	Pre-Transaction		Post-Mitigation	
	MW	Share	MW	Share
Exelon	9,566	30.49%	9,566	30.49%
NRG	1,058	3.37%	0	0.00%
Other	20,755	66.14%	21,813	69.51%
Total	31,379	100.00%	31,379	100.00%

Pre-Mitigation HHI Change: 206 HHI Change: 0

Finally, as shown in Table 10 below, the amount of unforced capacity in MAAC+APS as of June 1, 2009 was 73,013 MW. The HHI change pre-mitigation is 50 points, and the clean sweep mitigation results in an HHI change in the single digits, indicating that the transaction is well within safe harbor thresholds.

Table 10: Effect of the Transaction in MAAC+APS UCAP Market, as of 6/1/09

	Pre-Transaction		Post-Mitigation	
	MW	Share	MW	Share
Exelon	11,065	15.15%	11,204	15.35%
NRG	1,197	1.64%	0	0.00%
Other	60,751	83.21%	61,809	84.65%
Total	73,013	100.00%	73,013	100.00%

Pre-Mitigation HHI Change: 50 HHI Change: 3

74 The unusually large difference between the change in HHI for capacity versus the change in HHI for super-peak energy is due to the large amount of import capacity into PJM East that is factored into the energy market but not the capacity market.

Q. WHAT DID YOU CONCLUDE FROM YOUR ANALYSIS OF PJM ANCILLARY SERVICES MARKETS?

A. My analysis demonstrates that there are no competitive concerns raised in PJM ancillary services markets. PJM operates two market-based ancillary services markets: Synchronized Reserve and Regulation. Both the Regulation and Synchronized Reserve Markets are cleared on a real-time basis. A unit can be selected for either regulation or synchronized reserve, but not for both. PJM does not have an imbalance energy market distinct from its real-time energy market. PJM ancillary services markets are co-optimized with energy markets, and, under PJM rules, all generators that participates in the RPM capacity market must bid into the day-ahead energy market. Hence, physical withholding from the co-optimized market from which ancillary services are procured is not possible, even if ancillary services are not bid explicitly. As I discuss below, the expected participation of Exelon and NRG in ancillary services market is too small to suggest a likelihood of economic withholding.

Effective February 1, 2007, PJM created an "RFC Synchronized Reserve Zone", which consists of the overall RTO footprint excluding Dominion. Exelon typically offers about 270 MW of such reserves, compared to an average total amount that is offered and eligible of about 2,400 MW, implying an Exelon share of about 11 percent. Most of Exelon's offered capacity is from its controlled coal-fired facilities, primarily Kincaid. Given the clean sweep commitment, the only increase in Applicant's generation will result from Exelon's acquisition of NRG's small shares of Keystone and Conemaugh, the 12 MW Paxton Creek plant, and its Rockford peaking station in Illinois. None of these units will cause a material increase in the amount of synchronized reserve-capable units controlled by Exelon. In order to provide synchronized reserve, a generator must be synchronized to the system and capable of providing output within 10 minutes. Typically, deep baseload units such as Keystone and Conemaugh are not participating in the Synchronized Reserve market, because they are fully loaded already and the opportunity cost of participating in the market is high.[75] In any event, neither Exelon nor NRG operates or bids energy and ancillary services for Keystone and Conemaugh plants, which are operated by Reliant Energy on behalf of the joint owners. NRG's Rockford peaking units, like the Exelon peaking units in the western portion of PJM, are rarely in merit (average capacity factor of about 2 percent) and thus are not well-suited to providing synchronized reserves. Clearly, this level of generation, even if it could and did participate in the Synchronized Reserve market, is not large enough to create any competitive effect when combined with Exelon's generation in PJM. While I do not have any data on the ability of NRG's units to participate in the Synchronized Reserve market, a reasonable estimate can be made based on the capability of similar Exelon units for which I do have data. On that basis, I estimate that the NRG units could be expected to be offering about 59 MW of Synchronized Reserves, which is approximately 2 percent of the total amount offered and eligible for the region.[76] This implies an HHI change from the combination of about 50 points, and, therefore, the merger does not give rise to a competitive concern in this region.

Moreover, prices in the synchronous reserve market already are fully mitigated in that all Synchronized Reserve bids are offer capped on a cost basis by PJM.[77] Since the PJM Market Monitor continues to believe that the synchronous reserve market is not structurally competitive, it is likely that the market will remain mitigated during the interim period.

75 Theoretically, baseload coal units might be able to offer some Synchronized Reserve in low-load, or overnight hours when they are not fully loaded or when they otherwise are not expected to be running at full capacity. The very high capacity factors for these units indicate that this occurs rarely if ever. Keystone and Conemaugh each had capacity factors of about 93 percent for the past twelve months.

76 For example, none of Exelon's peaking units in Illinois are offering into the Synchronized Reserve market, and I assume the same for Rockford. Exelon's Eddystone 1&2 and Cromby 1 offer a modest amount of Synchronized Reserves, equivalent to about 2 percent of their installed capacity. Assuming the same for Indian River, means about 16 MW of reserves might typically be offered. Matching up NRG's Vienna oil steam unit to Exelon's Cromby 2 and Eddystone 3&4 implies about 5 MW of reserves. Matching up the non-Illinois peakers to Exelon's Schuykill and Falls units implies about 38 MW of reserves.

77 *2007 PJM SOM Report*, Vol. 1, p. 35.

PJM has operated a single, RTO-wide Regulation Market since August 2005. Units can provide regulation only if they have Automatic Generation Control ("AGC") that allows them to be dispatched directly by the ISO. Saleable regulation is limited to the amount by which the units can ramp in 5 minutes. Exelon units that bid regulation have an aggregate capability of about 350 MW, about 20 percent of the amount that is offered and eligible on average. However, this materially overstates Exelon's importance to this market. About 200 MW of the regulation capability that Exelon offers is from the Muddy Run pumped storage facility and is available only when each of the eight Muddy Run units is on line. Regulation can be provided only from generation that actually is synchronized and running. Muddy Run typically produces power only during daytime hours and typically is not fully loaded even then (due to water and pumping capability limitations).[78] The remaining 150 MW of regulation Exelon bids is from its baseload coal units. During the daytime hours when some or all of Muddy Run is in the regulation market, the opportunity cost of providing regulation from baseload coal is sufficiently high relative to alternatives (e.g., combined cycle units) that the will be selected to provide regulation less frequently than in off-peak periods. For these reasons, Exelon's maximum amount of regulation is likely to rarely exceed 200 MW during the day and 150 MW during the night.

A rationale similar to that used for the synchronous reserve market holds for why NRG's ability to provide regulation is small, even assuming NRG's units are all equipped with AGC. None of the NRG generation that will ultimately be owned by Exelon is particularly suited to provide regulation, and it is simply not large enough to create any competitive effect if combined with Exelon's generation. The addition of NRG's small share of Keystone and Conemaugh is too small to have an effect on the regulation market and, in any event, bids for that generation are not made by NRG and will not be made by Exelon. None of Exelon's peaking units in Illinois are providing regulation, and the situation is likely the same with respect to the Rockford units since they, too, are rarely on-line and peaking units, which tend to be block loaded, are poor candidates for regulation service.

78 In the 12 month period ending September 30, 2008 the average amount of Muddy Run regulation procured by the PJM system operator in on-peak hours was 68 MW and the average amount procured in weekday off-peak hours was 2 MW.

Prior to divesting the NRG units in PJM, the additional capacity not yet divested by Exelon will have a small capability in the regulation market. Going through the same estimation process as I used with respect to synchronous reserves, I estimate that the NRG units might be offering about 57 MW of Regulation, about 3 percent of the amount offered and eligible.[79] During overnight periods, Exelon's existing generation accounts for about 8.3 percent of regulation supply, so the change in HHI will be about 50 points. During peak periods, when Exelon's share of regulation is higher because Muddy Run is generating, NRG's share is probably lower, so that there still will be only a small increase in the HHI for regulation. As discussed previously, notwithstanding this lack of impact of the transaction on PJM ancillary services, Exelon is proposing to mitigate its bids for ancillary services during the interim period.

ERCOT

Q. DID YOU ANALYZE ERCOT MARKETS?

A. Yes. I examined an ERCOT market, as well as the North and Houston zones within ERCOT, where both Exelon and NRG own generation. However, to the extent these generating assets are located within ERCOT and do not sell out of ERCOT, the impact of the merger resulting from ownership of this generation on markets jurisdictional to the Commission is inherently limited. [80] As discussed below, there is a relatively weak interconnection between ERCOT and jurisdictional areas outside of ERCOT, namely the DC ties between ERCOT and the CSWS balancing authority area. Further, little, if any,

79 As noted, none of Exelon's peaking units in Illinois are offering into the Regulation market, and I assume the same for Rockford. Exelon's Eddystone 1&2 and Cromby 1 offer a modest amount of Regulation, equivalent to about 6 percent of their installed capacity. Assuming the same for Indian Point, means about 53 MW of regulation might typically be offered. None of Exelon's oil steam units are offering regulation, so I assumed none for Vienna. Based on Exelon's share of Keystone and Conemaugh regulation, NRG's share of regulation would be about 4 MW. The only other Exelon units typically are offering in the regulation market is Muddy Run, a pumped storage unit, for which NRG has no comparable unit.

80 Texas statutes give the PUCT jurisdiction to review the impact of this transaction on ERCOT and specify the test to be used in evaluating a merger's competitive effects.

output of the generating plants owned by Exelon and NRG in ERCOT participate in markets outside of ERCOT.[81]

Q. PLEASE DESCRIBE GENERALLY THE ERCOT ZONES AND TRANSMISSION INTERCONNECTIONS WITH THE EASTERN INTERCONNECTION.

A. ERCOT is presently made up of four “Commercially Significant Constraint” zones: Houston, North, West and South. ERCOT is interconnected with the Eastern Interconnection (into the Southwest Power Pool (“SPP”)) by two high voltage direct current (“HVDC”) ties, with a total capacity of 820 MW.[82] The 600 MW East DC tie is located between the Monticello substation in ERCOT (in the North zone) and the Welsh substation in SPP (within the CSWS balancing authority area). The 220 MW North DC Tie is located between the Oklaunion substations in ERCOT (in the West zone) and SPP (within the CSWS balancing authority area).

For 2009, based on a review of confirmed reservations from SPP’s OASIS, it appears that all of the capacity on the East and North DC Ties is reserved into ERCOT by parties unaffiliated with Exelon or NRG. Similarly, the capacity on the North DC Tie from ERCOT into SPP appears to be committed to parties not affiliated with Exelon or NRG. For purposes of modeling ERCOT, I assumed that the DC ties were allocated to the parties having firm reservations.[83] For purposes of my analysis of the Houston and North zones, I assumed imports equivalent to maximum flows reported by ERCOT, and also conducted sensitivities around this assumption.

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81 The exception is the Frontier facility, which is also interconnection to the EES balancing authority area.

82 There are no connections between ERCOT and the Western Interconnection, but ERCOT also is interconnected with CFE in Mexico (286 MW).

83 The results of my analysis are not particularly sensitive to this assumption. Typically, I would allocate transmission reservations only if there were a specific resource at the source being used to supply the importing location.

Q. WHERE IS EXELON'S AND NRG'S GENERATION IN ERCOT LOCATED?

The location of Exelon's and NRG's generation in ERCOT is summarized in Table 11 below.

Table 11: Exelon and NRG Generation in ERCOT

	Exelon (MW)	NRG (MW)
North Zone	3,253	1,689
Houston Zone	152	10,260
South and West Zones	0	1,320
ERCOT	3,405	13,269

Exelon owns or controls approximately 3,200 MW of generation in the North Zone, consisting of Mountain Creek (788 MW), Handley (1,262 MW), and contracted generation (AES Wolf Hollow (350 MW) and Tenaska Frontier (853 MW). As noted earlier, Frontier also is interconnected to the EES balancing authority area. As detailed in Exhibit J-3, not included in the total above is 190 MW of Exelon's generation (two Mountain Creek and two Handley units) that is currently mothballed and will soon be decommissioned. Exelon also owns the 152 MW LaPorte facility in the Houston zone.

NRG owns 1,689 MW in the North Zone (the Limestone facility), approximately 10,000 MW in the Houston zone (including 272 MW of new generation planned to be in-service in 2009 and approximately 2,200 MW of generation that is mothballed), and 1,320 MW in the South and West zones (including about 200 MW of generation planned to be in-service in 2009).

Q. WHAT ANALYSIS DID YOU CONDUCT OF THE ERCOT MARKET?

A. I conducted a full Economic Capacity Competitive Analysis Screen as would be required by the Commission in jurisdictional markets. I evaluated the ERCOT Economic Capacity market as a whole as well as the North and Houston zones. The analysis clearly demonstrates that, given the proposed "clean sweep" mitigation, the merger does not raise competitive concerns.

Q. PLEASE DESCRIBE YOUR ANALYSIS OF THE ERCOT MARKET.

A. My analysis of the ERCOT is based on total installed capacity in ERCOT, including units "switchable" between ERCOT and other regions, such as the Frontier facility, plus the import capability on the DC ties. I included generation expected to be on-line in 2009, as reported in Energy Velocity's database. This includes all existing units including those listed as "generation from private networks" in ERCOT's database (essentially generation used primarily "behind the fence" to serve on-site load (for example, several large generating facilities owned by Calpine Corp. and others).[84] I have also included mothballed generation, which is conservative in that NRG's mothballed units represent more than half of mothballed units in ERCOT.

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

A. The ERCOT market is unconcentrated post-merger, so that there is no level of HHI change that signals a potential market power problem As shown in Table 12 below and Exhibit J-10, Exelon's pre-transaction share of ERCOT is between 2 and 4 percent, and NRG's is between 10 and 16 percent. The HHI changes are at most 122 points and are largest during the peak time periods, when Exelon's higher cost capacity meets the economic facet of the DPT (*i.e.*, when in addition to the combined-cycle generation owned or contracted to Exelon, Exelon's higher cost capacity at the Handley, Mt. Creek and LaPorte facilities is also considered economic to operate).

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84 ERCOT capacity data from *Report on the Capacity, Demand, and Reserves in the ERCOT Region*. http://www.ercot.com/news/presentations/2008/2008_Capacity,_Demand,_Reserves_Report_FINAL.xls

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Table 12: Economic Capacity, ERCOT (pre-mitigation)

		Pre-Merger							Post-Merger (Pre-Mitigation)			
		Exelon		NRG								
Period	Price	MW	Mkt Share	MW	Mkt Share	Market Size	HHI		MW	Mkt Share	HHI	HHI Chg
S_SP1	$250	2,995	3.8%	12,502	15.9%	78,427	847		15,497	19.8%	969	122
S_SP2	$130	2,995	3.8%	12,502	16.0%	78,404	847		15,497	19.8%	969	122
S_P	$ 75	2,750	3.7%	11,720	15.9%	73,801	865		14,470	19.6%	983	118
S_OP	$ 65	1,118	1.9%	9,231	15.5%	59,386	790		10,349	17.4%	848	59
W_SP	$ 90	2,964	3.8%	11,932	15.5%	77,085	822		14,896	19.3%	941	119
W_P	$ 60	1,114	2.2%	5,285	10.2%	51,724	700		6,399	12.4%	744	44
W_OP	$ 55	1,114	2.2%	5,285	10.3%	51,367	696		6,399	12.5%	741	45
SH_SP	$100	2,803	4.0%	10,858	15.3%	70,873	807		13,661	19.3%	928	121
SH_P	$ 70	1,505	2.4%	9,600	15.2%	63,171	827		11,105	17.6%	900	72
SH_OP	$ 50	1,072	2.6%	4,208	10.1%	41,734	758		5,279	12.7%	809	52

Q. WHAT DID YOUR ANALYSIS SHOW FOR ECONOMIC CAPACITY IN THE NORTH ZONE?

A. In the North zone, Exelon's pre-transaction share is between 5 and 9 percent, and NRG's is between 9 and 11 percent. ERCOT North is either moderately concentrated or highly concentrated post-merger and the HHI changes exceed 100 points in six time periods. All of Exelon's ERCOT capacity except LaPorte is located in the North zone. NRG's only facility in the North zone is Limestone, with the remaining generation shown for NRG in Table 13 below coming from NRG's allocation of imports into the North zone.

Table 13: Economic Capacity, North Zone (pre-mitigation)

		Pre-Merger							Post-Merger (Pre-Mitigation)			
		Exelon		NRG								
Period	Price	MW	Mkt Share	MW	Mkt Share	Market Size	HHI		MW	Mkt Share	HHI	HHI Chg
S_SP1	$250	2,878	8.4%	3,123	9.1%	34,370	1,762		6,001	17.5%	1,914	152
S_SP2	$130	2,878	8.4%	3,123	9.1%	34,347	1,760		6,001	17.5%	1,912	152
S_P	$ 75	2,750	8.3%	3,162	9.6%	32,971	1,757		5,912	17.9%	1,916	160
S_OP	$ 65	1,118	4.2%	2,941	11.0%	26,837	1,495		4,059	15.1%	1,586	91
W_SP	$ 90	2,842	8.4%	2,932	8.7%	33,705	1,660		5,774	17.1%	1,807	147
W_P	$ 60	1,114	4.4%	2,243	8.9%	25,104	1,236		3,357	13.4%	1,315	79
W_OP	$ 55	1,114	4.4%	2,244	8.9%	25,104	1,229		3,358	13.4%	1,308	79
SH_SP	$100	2,697	8.6%	2,790	8.9%	31,382	1,618		5,487	17.5%	1,771	153
SH_P	$ 70	1,505	5.4%	2,775	9.9%	28,087	1,635		4,280	15.2%	1,741	106
SH_OP	$ 50	1,072	4.7%	2,151	9.4%	22,945	1,236		3,222	14.0%	1,324	88

Q. WHAT DID YOUR ANALYSIS SHOW FOR ECONOMIC CAPACITY IN THE HOUSTON ZONE?

A. In the Houston zone, Exelon's pre-transaction share is between 1 and 2 percent, and NRG's is between 18 and 39 percent. The Houston zone is either moderately concentrated (5 periods) or highly concentrated (5 periods) post-merger and the screen is not passed in five of the ten time periods. Exelon's only facility in the Houston zone is LaPorte, a peaking facility that is only economic during the highest peak periods, with the remaining generation shown in Table 14 below from Exelon's allocation of imports into the Houston zone.

Table 14: Economic Capacity, Houston Zone (pre-mitigation)

	Pre-Merger							Post-Merger (Pre-Mitigation)			
		Exelon		NRG							
Period	Price	MW	Mkt Share	MW	Mkt Share	Market Size	HHI	MW	Mkt Share	HHI	HHI Chg
S_SP1	$250	483	1.8%	10,193	38.9%	26,202	1,875	10,676	40.8%	2,018	143
S_SP2	$130	483	1.8%	10,193	38.9%	26,202	1,875	10,676	40.8%	2,018	143
S_P	$ 75	349	1.5%	9,426	39.4%	23,932	1,977	9,776	40.9%	2,092	115
S_OP	$ 65	184	0.9%	7,034	33.1%	21,262	1,639	7,217	33.9%	1,696	57
W_SP	$ 90	519	1.9%	9,905	35.8%	27,711	1,667	10,424	37.6%	1,801	134
W_P	$ 60	217	1.1%	3,429	17.9%	19,200	1,138	3,646	19.0%	1,178	40
W_OP	$ 55	217	1.1%	3,431	17.9%	19,200	1,140	3,649	19.0%	1,180	40
SH_SP	$100	504	2.0%	9,012	36.0%	25,037	1,668	9,516	38.0%	1,813	145
SH_P	$ 70	243	1.1%	7,792	35.0%	22,249	1,696	8,035	36.1%	1,773	76
SH_OP	$ 50	228	1.6%	2,541	18.2%	13,993	1,193	2,769	19.8%	1,252	59

Q. GIVEN EXELON'S "CLEAN SWEEP" MITIGATION COMMITMENT IN ERCOT, WHAT ARE THE POST-MITIGATION RESULTS FOR THE ERCOT MARKET AND THE NORTH AND HOUSTON ZONES?

A. There were no screen failures in an ERCOT-wide market; however, the mitigation of screen failures in the North and Houston zones will similarly improve the results for the overall ERCOT market. The exact numerical results post-mitigation depend on the parties that ultimately acquire Exelon's capacity in ERCOT. Post-mitigation, Exelon will have precisely the same share of ERCOT and the relevant zonal markets as NRG's pre-transaction share.

Table 15 shows the results for the ERCOT market and Table 16 and Table 17 show the results in the North and Houston zones, respectively, if all of Exelon's capacity in ERCOT were sold to a hypothetical single, new entrant into ERCOT. Exhibit J-8 and these tables also provide the post-mitigation results. Given the "clean sweep" mitigation, the HHI changes are reduced to zero.

Table 15: Economic Capacity, ERCOT (post-mitigation)

	Pre-Merger							Post-Merger (Pre-Mitigation)			
		Exelon		NRG							
Period	Price	MW	Mkt Share	MW	Mkt Share	Market Size	HHI	MW	Mkt Share	HHI	HHI Chg
S_SP1	$250	2,995	3.8%	12,502	15.9%	78,427	847	12,502	15.9%	847	—
S_SP2	$130	2,995	3.8%	12,502	16.0%	78,404	847	12,502	16.0%	847	—
S_P	$ 75	2,750	3.7%	11,720	15.9%	73,801	865	11,720	15.9%	865	—
S_OP	$ 65	1,118	1.9%	9,231	15.5%	59,386	790	9,231	15.5%	790	—
W_SP	$ 90	2,964	3.8%	11,932	15.5%	77,085	822	11,932	15.5%	822	—
W_P	$ 60	1,114	2.2%	5,285	10.2%	51,724	700	5,285	10.2%	700	—
W_OP	$ 55	1,114	2.2%	5,285	10.3%	51,367	696	5,285	10.3%	696	—
SH_SP	$100	2,803	4.0%	10,858	15.3%	70,873	807	10,858	15.3%	807	—
SH_P	$ 70	1,505	2.4%	9,600	15.2%	63,171	827	9,600	15.2%	827	—
SH_OP	$ 50	1,072	2.6%	4,208	10.1%	41,734	758	4,208	10.1%	758	—

Table 16: Economic Capacity, North Zone (post-mitigation)

	Pre-Merger							Post-Merger (Pre-Mitigation)			
		Exelon		NRG							
Period	Price	MW	Mkt Share	MW	Mkt Share	Market Size	HHI	MW	Mkt Share	HHI	HHI Chg
S_SP1	$250	2,878	8.4%	3,123	9.1%	34,370	1,762	3,123	9.1%	1,762	—
S_SP2	$130	2,878	8.4%	3,123	9.1%	34,347	1,760	3,123	9.1%	1,760	—
S_P	$ 75	2,750	8.3%	3,162	9.6%	32,971	1,757	3,162	9.6%	1,757	—
S_OP	$ 65	1,118	4.2%	2,941	11.0%	26,837	1,495	2,941	11.0%	1,495	—
W_SP	$ 90	2,842	8.4%	2,932	8.7%	33,705	1,660	2,932	8.7%	1,660	—
W_P	$ 60	1,114	4.4%	2,243	8.9%	25,104	1,236	2,243	8.9%	1,236	—
W_OP	$ 55	1,114	4.4%	2,244	8.9%	25,104	1,229	2,244	8.9%	1,229	—
SH_SP	$100	2,697	8.6%	2,790	8.9%	31,382	1,618	2,790	8.9%	1,618	—
SH_P	$ 70	1,505	5.4%	2,775	9.9%	28,087	1,635	2,775	9.9%	1,635	—
SH_OP	$ 50	1,072	4.7%	2,151	9.4%	22,945	1,236	2,151	9.4%	1,236	—

Table 17: Economic Capacity, Houston Zone (post-mitigation)

	Pre-Merger								Post-Merger (Pre-Mitigation)			
		Exelon		NRG								
Period	Price	MW	Mkt Share	MW	Mkt Share	Market Size	HHI	MW	Mkt Share	HHI	HHI Chg
S_SP1	$250	483	1.8%	10,193	38.9%	26,202	1,875	10,193	38.9%	1,875	—
S_SP2	$130	483	1.8%	10,193	38.9%	26,202	1,875	10,193	38.9%	1,875	—
S_P	$ 75	349	1.5%	9,426	39.4%	23,932	1,977	9,426	39.4%	1,977	—
S_OP	$ 65	184	0.9%	7,034	33.1%	21,262	1,639	7,034	33.1%	1,639	—
W_SP	$ 90	519	1.9%	9,905	35.8%	27,711	1,667	9,905	35.8%	1,667	—
W_P	$ 60	217	1.1%	3,429	17.9%	19,200	1,138	3,429	17.9%	1,138	—
W_OP	$ 55	217	1.1%	3,431	17.9%	19,200	1,140	3,431	17.9%	1,140	—
SH_SP	$100	504	2.0%	9,012	36.0%	25,037	1,668	9,012	36.0%	1,668	—
SH_P	$ 70	243	1.1%	7,792	35.0%	22,249	1,696	7,792	35.0%	1,696	—
SH_OP	$ 50	228	1.6%	2,541	18.2%	13,993	1,193	2,541	18.2%	1,193	—

Q. IS THERE ANY IMPACT OF THE TRANSACTION ON ERCOT ANCILLARY SERVICES MARKETS?

A. Given the clean sweep mitigation, there will be no effect on ancillary services markets in ERCOT. With respect to the interim period, it is not possible to formally analyze the effect of the transaction on ancillary services in ERCOT due to the absence of necessary data for market participants other than Exelon. As discussed previously, the unconcentrated nature of the ERCOT-wide energy market makes it quite unlikely that there would be market power issues concerning ancillary services that are procured on an ERCOT-wide basis, and most of the ERCOT ancillary services are procured on an ERCOT-wide basis. One ancillary service, balancing energy, sometimes must be procured within a particular zone. As described earlier and in the application, Exelon is proposing cost-based bid mitigation for balancing energy during the interim period. This should eliminate any concern over economic withholding of balancing energy during the interim period. For the reasons discussed in the interim mitigation section of my testimony, there is no substantive possibility for Exelon (or anyone else) to physically withhold generation in ERCOT to any material degree.

Other Relevant Markets

Q. WHAT ARE THE RESULTS FOR THE CSWS MARKET?

A. The results for the CSWS market are shown in Table 18 and Table 19, below, for the Economic Capacity and Available Economic Capacity measures, respectively, and in Exhibit J-9. As noted earlier, a potential competitive concern arising from within ERCOT that is relevant to this filing relates to the impact of combining generation within ERCOT on jurisdictional markets outside of ERCOT. CSWS is the only balancing authority area that is first tier to ERCOT. The analysis of the CSWS balancing authority area primarily reflects the competitive effect of combined NRG's generation in ERCOT and the EES balancing authority area with the generation Exelon owns in ERCOT (pre-mitigation) and the controlled generation arising from contractual rights that Exelon has to the Green Country combined-cycle facility located in CSWS.

The results for the Economic Capacity measure are shown in Table 18 below. As shown, NRG's generation outside of the CSWS balancing authority area is allocated a small portion of transmission into the market and the HHI changes are miniscule.

Table 18: Economic Capacity, CSWS

	Pre-Merger							Post-Merger (Pre-Mitigation)			
		Exelon		NRG							
Period	Price	MW	Mkt Share	MW	Mkt Share	Market Size	HHI	MW	Mkt Share	HHI	HHI Chg
S_SP1	$250	521	3.8%	15	0.1%	13,557	4,517	536	4.0%	4,517	1
S_SP2	$130	521	3.9%	15	0.1%	13,528	4,517	536	4.0%	4,518	1
S_P	$ 80	521	4.0%	15	0.1%	13,153	4,410	536	4.1%	4,411	1
S_OP	$ 50	522	5.9%	20	0.2%	8,848	2,930	542	6.1%	2,933	3
W_SP	$ 90	514	3.8%	24	0.2%	13,392	4,053	539	4.0%	4,054	1
W_P	$ 65	516	4.3%	24	0.2%	12,018	3,707	541	4.5%	3,709	2
W_OP	$ 40	2	0.0%	43	1.0%	4,357	5,484	45	1.0%	5,484	—
SH_SP	$ 90	484	3.9%	28	0.2%	12,497	3,976	513	4.1%	3,978	2
SH_P	$ 70	487	4.1%	32	0.3%	11,886	3,860	519	4.4%	3,862	2
SH_OP	$ 40	2	0.1%	57	1.4%	4,221	4,891	59	1.4%	4,891	—

The results for the Available Economic Capacity measure are shown in Table 19, below. While NRG's generation outside of the CSWS balancing authority area is allocated a somewhat larger portion of transmission into the market, the HHI changes are still well within safe-harbor thresholds. When the market is highly concentrated (reflecting the fact that this market has not been restructured and a single entity must meet most of the load), the HHI changes are no more than 30 points. Only when the market is unconcentrated do HHI changes get a bit higher, but since the market remains unconcentrated the change in HHI is not a concern.

Table 19: Available Economic Capacity, CSWS

		Pre-Merger						Post-Merger (Pre-Mitigation)			
		Exelon		NRG							
Period	Price	MW	Mkt Share	MW	Mkt Share	Market Size	HHI	MW	Mkt Share	HHI	HHI Chg
S_SP1	$250	540	12.9%	17	0.4%	4,186	2,869	556	13.3%	2,879	10
S_SP2	$130	536	12.8%	16	0.4%	4,186	2,862	552	13.2%	2,871	10
S_P	$ 80	535	9.1%	15	0.3%	5,889	2,275	549	9.3%	2,279	5
S_OP	$ 50	533	12.8%	48	1.2%	4,153	2,809	582	14.0%	2,839	30
W_SP	$ 90	530	8.6%	22	0.4%	6,185	2,064	552	8.9%	2,070	6
W_P	$ 65	546	8.8%	28	0.5%	6,227	2,060	574	9.2%	2,068	8
W_OP	$ 40	14	1.7%	204	23.8%	857	892	218	25.5%	972	80
SH_SP	$ 90	513	10.2%	40	0.8%	5,050	1,960	553	11.0%	1,976	16
SH_P	$ 70	517	8.1%	29	0.5%	6,378	2,069	547	8.6%	2,077	7
SH_OP	$ 40	17	1.7%	209	20.8%	1,005	795	226	22.5%	866	71

Q. ARE THERE OTHER MARKETS IN WHICH EXELON AND NRG BOTH OWN OR CONTROL GENERATION?

A. Yes, there are two other such markets, ISO-NE and the EES balancing authority area.

Q. IS THERE A COMPETITIVE IMPACT OF THE TRANSACTION IN ISO-NE?

A. No. In ISO-NE, Exelon owns only 178 MW of generation, mostly located in the NEMA/Boston load pocket, with small amounts located in the Southern Maine and Rhode Island transmission sub-areas. NRG owns approximately 2,200 MW of generation, mostly located in the SWCT and CT load pockets.[85] As shown in Table 20, ISO-NE is a market with approximately 31,000 MW of installed generation. Exelon's market share is less than one percent, and NRG's share is about 7 percent. ISO-NE is an unconcentrated market[86] and Exelon's and NRG's shares are small. The HHI change is approximately 8 points. Both the market shares and the HHI change would be lower if imports were taken into consideration.

85 As noted in Exhibit J-4, much of NRG's generation in ISO-NE (in Connecticut and SWCT) is subject to Reliability Agreements. *See* http://www.iso-ne.com/genrtion_resrcs/reports/rmr/reliability_agreeement_status_summary.ppt#259,2,Reliability Agreements

86 The HHI for installed capacity in ISO-NE as of August 2007 was 525, well below the unconcentrated threshold of 1000 HHI. See *2007 Assessment of the Electricity Markets in New England*, Potomac Economics, Ltd., Independent Market Monitoring Unit, ISO New England Inc., June 2008, at 149. http://www.iso-ne.com/pubs/spcl_rpts/2007/isone_2007_immu_rpt_fin_6-30-08.pdf

Table 20: Effect of Transaction in ISO-NE

	MW	Share
Exelon	178	0.58%
NRG	2,204	7.13%
Other	28,520	92.29%
Total	30,902	100.00%
HHI Change: 8		

Because Exelon's and NRG's generation is located in separate areas within ISO-NE, there is no smaller relevant geographic market than ISO-NE as a whole, and, clearly, the effect of the merger in ISO-NE is not material, and a full Competitive Analysis Screen is not necessary.

Q. IS THERE A COMPETITIVE IMPACT OF THE TRANSACTION IN THE EES BALANCING AUTHORITY AREA?

A. No. In EES, Exelon owns no generation, but has a long-term PPA with respect to the 853 MW Tenaska Frontier generating facility that is also interconnected with ERCOT. This unit represents only about 2 percent of installed capacity in the EES balancing authority area. Further, Exelon has sold 300 MW of the output of the facility to Entergy until May 2010, dropping to 150 MW until May 2011.

NRG owns or controls approximately 2,400 MW of generation in the LAGN balancing authority area (which, as discussed earlier, is treated as part of the EES balancing authority area for analytical purposes), as well as a 600 MW toll under which NRG has the right to the Cottonwood facility in EES through February 2010. NRG's generation represents an approximately 7 percent share of installed capacity in EES. As shown in Table 21, EES is a market with almost 42,000 MW of installed generation.[87] The HHI change is approximately 29 points. Both the market shares and the HHI change would be lower if imports were taken into consideration.

87 *NERC 2008 Long-term Reliability Assessment (2008-2017)* (October 2008), Table 13a. http://www.nerc.com/files/LTRA2008.pdf

Table 21: Effect of Transaction in EES

	MW	Share
Exelon	853	2.05%
NRG	2,978	7.16%
Other	37,785	90.79%
Total	41,616	100.00%
HHI Change: 29		

As I discussed earlier, the majority of the output of NRG's generating facilities is used to supply load under long-term contracts to several distribution cooperatives and public power authorities in the market, and NRG has reported that "During limited peak demand periods, the load requirements of these contract customers exceed the baseload capacity of NRG's coal-fired Big Cajun II plant. During such peak demand periods, NRG typically employs its own gas fired assets, or alternatively purchases power from external sources frequently at higher prices than can be recovered under the Company's contracts."[88]

These facts alone support a determination that there are no competitive concerns raised by the transaction in the EES balancing authority area market. But in any event, because the "clean sweep" mitigation strategy involves divesting all of Exelon's owned or controlled generation in ERCOT, Exelon has committed to divest the control over generation it is deemed to have under the Tenaska Frontier contract. As a result of these commitments, the post-transaction Exelon share of generation in EES will simply be the current NRG share and hence, the competitive effect of the merger will be *de minimis*.

88 NRG's December 31, 2007 10-K, page 30. http://www.snl.com/Cache/5681447.pdf?O=3&IID=4057436&OSID=9&FID=5681447

Q. ARE THERE ANY OTHER RELEVANT MARKETS TO CONSIDER?

A. No. I did not analyze the following geographic markets because only one of the two merging parties owns or controls generation: MISO (where Exelon is the only applicant owning or controlling generation), and NYISO,[89] CAISO or NEVP (where NRG is the only applicant owning or controlling generation). In these markets, "the merging entities do not currently conduct business in the same geographic markets,"[90] and hence there is no material competitive effect.

In concluding that (i) the extent of business transactions in the same markets is *de minimis*, and (ii) no other markets need to be analyzed, I also reviewed data in the Electric Quarterly Reports ("EQR") of the Applicants. [91] These data are consistent with my conclusions.

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89 I have considered whether any concerns are raised in NYISO as a result of combining Exelon's generation in PJM with NRG's generation in NYISO, and conclude that the Transaction will have no material competitive effect in NYISO. As already noted, only NRG, and not Exelon, owns capacity in NYISO. Installed capacity in NYISO is 38,713 MW. Assuming a simultaneous transfer capability of 1,500 MW from PJM to NYISO, the market size is approximately 40,200 MW, and NRG's owned capacity in NYISO (4,051 MW) represents about 10 percent of the market. Post-transaction, Exelon will own 24,284 MW in PJM, 15 percent of installed capacity in PJM. Assuming a pro rata allocation of imports from PJM into NYISO (a conservative assumption given the location of Exelon's PJM generation), the extent of Exelon's participation in the NYISO market would be only 225 MW, or .06 percent. Such a share clearly is *de minimis*. Exelon also would be allocated a minute amount of generation from its New England facilities, a few MW during peak periods.

(Data are from New York Independent System Operator 2008 Load & Capacity Report, http://www.nyiso.com/public/webdocs/services/planning/planning_data_reference_documents/2008_NYCA_Generators.xls; 2008 PJM Load, Capacity and Transmission Report dated November 5, 2008. http://www.pjm.com/documents/downloads/reports/2008-pjm-411.xls; and *New York Control Area Installed Capacity Requirements for the Period May 2008 through April 2009*, Technical Study Report, December 14, 2007, New York State Reliability Council, LLC, Installed Capacity Subcommittee. http://www.nysrc.org/pdf/Reports/Final%202008%20IRM%20Report%2012-14-07%20_2_.pdf)

90 18 C.F.R. § 33.3(a)(2)(i). As I discuss in more detail below, there also are no concerns raised by the possibility of potential imports from one adjacent market to the other (e.g., ISO-NE and NYISO, or NYISO and PJM).

91 The data I examined cover EQR filings for 2006 through the third quarter of 2008. These data are included in my workpapers.

Vertical Market Power

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

A. The other primary potential market power issue is vertical market power — control over electric transmission, generating sites or fuels supplies. There are no issues about electric transmission market power since all of Exelon’s transmission is under the operational control of PJM and NRG does not own any transmission other than that necessary to connect its generation to the grid. As already discussed, there are no vertical concerns relating to the combination of PECO’s gas distribution operations which serve very little third party generation, and NRG’s generation in PJM, particularly given that all of NRG’s PJM East generation will be divested. As noted previously, three years ago the Commission found that the combination of Exelon and PSEG gave rise to no vertical market power concerns since the upstream gas market was not highly concentrated. This result was despite the fact that both PSEG and PECO, being gas distribution companies with significant gas supply requirements, were major holders of upstream capacity rights, aggregating to 36 percent of the market and contributing the bulk of the market HHI. PECO alone accounted for only 6 percent of the market. NRG’s market share is certain to be significantly less than PSEG’s 30 percent since it serves no gas customers. Indeed, based both on the data I examined in connection with the Exelon-PSEG merger, and current informational postings on gas transportation contracts, NRG has no material presence in the market for long-term contracts into PJM East.[92]

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

A. No. I was unable to identify any special barriers to entry in this regard. PECO’s and ComEd’s service areas are relatively small, and the relevant geographic markets in PJM encompass a large region and include many possible generating sites. Entrants who

92 NRG has a single, 20,000 mmbtu/d contract on Texas Eastern for delivery into PJM East. I understand that to the extent that contract is associated with its PJM East generation, it would be assigned to the buyer as part of the clean sweep divestiture.

could compete in areas potentially affected by this merger would not need to locate new facilities in Exelon's service areas or connect to Exelon's transmission systems. In any event, PJM, not Exelon, controls the interconnection process for new generation. Thus Exelon's PJM membership should moot any concerns in this regard.

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

A. In Order No. 888, the Commission in referring to a decision in *Entergy Services, Inc*., noted that "after examining generation dominance in many different cases over the years, we have yet to find an instance of generation dominance in long-run bulk power markets."[93] While the Commission has indicated its intent to review the presumption that long-term markets are competitive, there is no evidence to overcome that presumption in this case. Certainly, the entry of new generation into PJM and its ownership by numerous independent entities shows that entry is not constrained.

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

A. Yes. PJM has been capacity-long in recent years, and its reserve margin for the summer of 2008 was 18.8 percent based on committed capacity and 21.4 percent based on total capacity, both well in excess of the PJM required reserve margin of 15.0 percent.[94] However, PJM reports that there is about 54,000 MW of "active" generation in the interconnection queue, including almost 6,000 MW under construction.[95]

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

94 *PJM 2007 Summer Preseasonal Assessment*, http://www.pjm.com/planning/downloads/2007-pjm-summer-pre-seasonal-assessment.pdf.

95 *PJM RTO as of November 26, 2008, Megawatt Summary by Queue Letter*, November 26, 2008. ftp://ftp.pjm.com/pub/reports/planning/rto/20081126-RTO.pdf.

VI. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION.

A. I recommend that the Commission determine that this merger will not have an adverse effect on competition in markets subject to its jurisdiction and that mitigation beyond the commitments proposed by Exelon are not required.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

Exhibit No. J-1

EXHIBITS

Exhibit J-1	Testimony
Exhibit J-2	Resume of William H. Hieronymus
Exhibit J-3	Exelon's Generation
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Exhibit No. J-1

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WILLIAM H. HIERONYMUS
Vice President

Ph.D. Economics
University of Michigan

M.A. Economics
University of Michigan

B.A. Social Science
University of Iowa

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

EXPERIENCE

Electricity Sector Structure, Regulation, And Related Management And Planning Issues

U.S. Market Restructuring Assignments

- Dr. Hieronymus serves as an advisor to the senior executives of electric utilities on restructuring and related regulatory issues, and he has worked with senior management in developing strategies for shaping and adapting to the emerging competitive market in electricity. Related to some of these assignments, he has testified before state agencies on regulatory policies and on contract and asset valuation.

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- For utilities seeking merger approval, Dr. Hieronymus has prepared and testified to market power analyses at FERC and before state commissions. He also has assisted in discussions with the Antitrust Division of the Department of Justice and in responding to information requests. The mergers on which Dr. Hieronymus has testified include both electricity mergers and combination mergers involving electricity and gas companies. Among the major mergers on which he has testified are Duke Energy-Cinergy, EEG (Exelon and PSE&G), Sempra (Enova and Pacific Enterprises), Xcel (New Century Energy and Northern States Power), Exelon (Commonwealth Edison and Philadelphia Electric), AEP (American Electric Power and Central and Southwest), Dynegy-Illinois Power, Con Edison-Orange and Rockland, Dominion-Consolidated Natural Gas, NiSource-Columbia Energy, E-on-PowerGen/LG&E and NYSEG-RG&E. He also submitted testimony in mergers that were terminated for unrelated reasons, including Entergy-Florida Power and Light, Northern States Power and Wisconsin Energy, KCP&L and Utilicorp and Consolidated Edison-Northeast Utilities. Testimony on similar topics has been filed for a number of smaller utility mergers and for numerous asset acquisitions. Dr Hieronymus has also assisted numerous clients in the pre-merger screening of potential acquisitions and merger partners.
- For utilities seeking to establish or extend market rate authority, Dr. Hieronymus has provided numerous analyses concerning market power in support of submissions under Sections 205 of the Federal Power Act.
- For utilities and power pools engaged in restructuring activities, he has assisted in examining various facets of proposed reforms. Such analysis has included features of the proposals affecting market efficiency and those that have potential consequences for market power. Where relevant, the analysis also has examined the effects of alternative reforms on the client’s financial performance and achievement of other objectives.
- For generators and marketers, Dr. Hieronymus has testified extensively in the regulatory proceedings concerning the electricity crisis in the WECC that occurred during May 2000 and May 2001. His testimony concerned, inter alia, the economics of long term contracts entered into during that period, the behavior of market participants during the crisis period and the nexus between purportedly dysfunctional spot markets and forward contracts. In the context of investigations into economic and physical withholding, he prepared and sponsored analyses of the specific behaviors of client generating companies relating to the nature and causes of their activities and the profits earned from them.
- For the New England Power Pool (NEPOOL), Dr. Hieronymus examined the issue of market power in connection with NEPOOL’s movement to market-based pricing for energy, capacity, and ancillary services. He also assisted the New England utilities in preparing their market power mitigation proposal. The main results of his analysis were incorporated in NEPOOL’s market power filing before FERC and in ISO-New England’s market power mitigation rules.
- On behalf of Consolidated Edison, he drafted and sponsored market power mitigation rules relating to energy and capacity sales in the New York City load pocket.

- For a coalition of independent generators, he provided affidavits advising FERC on changes to the rules under which the northeastern U.S. power pools operate.
- Dr. Hieronymus has contributed substantially to projects dealing with the restructuring of the California electricity industry. In this context he also is a witness in California and FERC proceedings on the subject of market power and mitigation and more recently before FERC in connection with transactions related to PG&E's bankruptcy and on the contracts signed between merchant generators and various buyers.

Valuation of Utility Assets in North America

- Dr. Hieronymus has testified in state securitization and stranded cost quantification proceedings, primarily in forecasting the level of market prices that should be used in assessing the future revenues and the operating contribution earned by the owner of utility assets in energy and capacity markets. The market price analyses are tailored to the specific features of the market in which a utility will operate and reflect transmission-constrained trading over a wide geographic area. He also has testified in rebuttal to other parties' testimony concerning stranded costs, and has assisted companies in internal stranded cost and asset valuation studies.
- He was the primary valuation witness on behalf of a western utility in an arbitration proceeding concerning the value of a combined cycle plant coming off lease that the utility wished to purchase.
- He assisted a bidder in determining the commercial terms of plant purchase offers as well as assisting clients in assessing the regulatory feasibility of potential acquisitions and mergers.
- He has testified in bankruptcy court and in arbitration proceedings concerning the value of terminated long term contracts in connection with contract defaults by bankrupt power marketers and merchant generators.

Other U.S. Utility Engagements

- Dr. Hieronymus has contributed to the development of several benchmarking analyses for U.S. utilities. These have been used in work with clients to develop regulatory proposals, set cost reduction targets, restructure internal operations, and assess merger savings.
- Dr. Hieronymus was a co-developer of a market simulation package tailored to region-specific applications. He and other senior personnel have conducted numerous multi-day training sessions using the package to help utility clients in educating management regarding the consequences of wholesale and retail deregulation and in developing the skills necessary to succeed in this environment.
- He has made numerous presentations to U.S. utility managements regarding overseas electricity systems.

- In connection with nuclear generating plants nearing completion, he has testified in Pennsylvania, Louisiana, Arizona, Illinois, Missouri, New York, Texas, Arkansas, New Mexico, and before the Federal Energy Regulatory Commission regarding plant-in-service rate cases on the issues of equitable and economically efficient treatment of plant costs for tariff-setting purposes, regulatory treatment of new plants in other jurisdictions, the prudence of past system planning decisions and assumptions, performance incentives, and the life-cycle costs and benefits of the units. In these and other utility regulatory proceedings, Dr. Hieronymus and his colleagues have provided extensive support to counsel, including preparation of interrogatories, cross-examination support, and assistance in writing briefs.
- On behalf of utilities in the states of Michigan, Massachusetts, New York, Maine, Indiana, Pennsylvania, New Hampshire, and Illinois, he has submitted testimony in regulatory proceedings on the economics of completing nuclear generating plants that were then under construction. His testimony has covered the likely cost of plant completion; forecasts of operating performance; and extensive analyses of the impacts of completion, deferral, and cancellation upon ratepayers and shareholders. For the senior managements and boards of utilities engaged in nuclear plant construction, Dr. Hieronymus has performed a number of highly confidential assignments to support strategic decisions concerning the continuance of construction.
- For an eastern Pennsylvania utility that suffered a nuclear plant shutdown due to NRC sanctions relating to plant management, he filed testimony regarding the extent to which replacement power cost exceeded the costs that would have occurred but for the shutdown.
- For a major Midwestern utility, Dr. Hieronymus headed a team that assisted senior management in devising its strategic plans, including examination of such issues as plant refurbishment/life extension strategies, impacts of increased competition, and available diversification opportunities.
- On behalf of two West Coast utilities, Dr. Hieronymus testified in a needs certification hearing for a major coal-fired generation complex concerning the economics of the facility relative to competing sources of power, particularly unconventional sources and demand reductions.
- For a large western combination utility, he participated in a major 18-month effort to provide the client with an integrated planning and rate case management system.
- For two Midwestern utilities, Dr. Hieronymus prepared an analysis of intervenor-proposed modifications to the utilities' resource plans. He then testified on their behalf before a legislative committee.

U.K. Assignments

- Following promulgation of the white paper that established the general framework for privatization of the electricity industry in the United Kingdom, Dr. Hieronymus participated extensively in the task forces charged with developing the new market system and regulatory regime. His work on behalf of the Electricity Council and the twelve regional distribution and retail supply companies focused on the proposed regulatory regime, including the price cap and regulatory formulas, and distribution and transmission use of system tariffs. He was an active participant in industry-government task forces charged with creating the legislation, regulatory framework, initial contracts, and rules of the pooling and settlements system. He also assisted the regional companies in the valuation of initial contract offers from the generators, including supporting their successful refusal to contract for the proposed nuclear power plants that subsequently were canceled as being non-commercial.
- During the preparation for privatization, Dr. Hieronymus assisted several individual U.K. electricity companies in understanding the evolving system, in developing use of system tariffs, and in enhancing commercial capabilities in power purchasing and contracting. He continued to advise a number of clients, including regional companies, power developers, large industrial customers, and financial institutions on the U.K. power system for a number of years after privatization.
- Dr. Hieronymus assisted four of the regional electricity companies in negotiating equity ownership positions and developing the power purchase contracts for a 1,825 megawatt combined cycle gas station. He also assisted clients in evaluating other potential generating investments including cogeneration and non-conventional resources.
- Dr. Hieronymus also has consulted on the separate reorganization and privatization of the Scottish electricity sector. Part of his role in that privatization included advising the larger of the two Scottish companies and, through it, the Secretary of State on all phases of the restructuring and privatization, including the drafting of regulations, asset valuation, and company strategy.
- He assisted one of the Regional Electricity Companies in England and Wales in the 1993 through 1995 regulatory proceedings that reset the price caps for its retailing and distribution businesses. Included in this assignment was consideration of such policy issues as incentives for the economic purchasing of power, the scope of price control, and the use of comparisons among companies as a basis for price regulation. Dr. Hieronymus's model for determining network refurbishment needs was used by the regulator in determining revenue allowances for capital investments.
- He assisted one of the Regional Electricity Companies in its defense against a hostile takeover, including preparation of its submission to the Cabinet Minister who had the responsibility for determining whether the merger should be referred to the competition authority.

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

- Dr. Hieronymus testified before the federal court of Australia concerning the market power implications of acquisition of a share of a large coal-fired generating facility by a large retail and distribution company.
- Dr. Hieronymus assisted a large state-owned European electricity company in evaluating the impacts of the 1997 EU directive on electricity that inter alia requires retail access and competitive markets for generation. The assignment included advice on the organizational solution to elements of the directive requiring a separate transmission system operator and the business need to create a competitive marketing function.
- For the European Bank for Reconstruction and Development, he performed analyses of least-cost power options and evaluated the return on a major investment that the Bank was considering for a partially completed nuclear plant in Slovakia. Part of this assignment involved developing a forecast of electricity prices, both in Eastern Europe and for potential exports to the West.
- For the OECD he performed a study of energy subsidies worldwide and the impact of subsidy elimination on the environment, particularly on greenhouse gases.
- For the Magyar Villamos Muvek Troszt, the electricity company of Hungary, Dr. Hieronymus developed a contract framework to link the operations of the different entities of an electricity sector in the process of moving from a centralized command- and-control system to a decentralized, corporatized system.
- For Iberdrola, the largest investor-owned Spanish electricity company, he assisted in development of their proposal for a fundamental reorganization of the electricity sector, its means of compensating generation and distribution companies, its regulation, and the phasing out of subsidies. He also has assisted the company in evaluating generation expansion options and in valuing offers for imported power.
- Dr. Hieronymus contributed extensively to a project for the Ukrainian Electricity Ministry, the goal of which was to reorganize the Ukrainian electricity sector and prepare it for transfer to the private sector and the attraction of foreign capital. The proposed reorganization is based on regional electric power companies, linked by a unified central market, with market-based prices for electricity.
- At the request of the Ministry of Power of the USSR, Dr. Hieronymus participated in the creation of a seminar on electricity restructuring and privatization. The seminar was given for 200 invited Ministerial staff and senior executives of the USSR power system. His specific role was to introduce the requirements and methods of privatization. Subsequent to the breakup of the Soviet Union, Dr. Hieronymus continued to advise both the Russian energy and power ministry and the government-owned generation and transmission company on restructuring and market development issues.

- On behalf of a large continental electricity company, Dr. Hieronymus analyzed the proposed directives from the European Commission on gas and electricity transit (open access regimes) and on the internal market for electricity. The purpose of this assignment was to forecast likely developments in the structure and regulation of the electricity sector in the common market and to assist the client in understanding their implications.
- For the electric utility company of the Republic of Ireland, he assessed the likely economic benefit of building an interconnector between Eire and Wales for the sharing of reserves and the interchange of power.
- For a task force representing the Treasury, electricity generating, and electricity distribution industries in New Zealand, Dr. Hieronymus undertook an analysis of industry structure and regulatory alternatives for achieving the economically efficient generation of electricity. The analysis explored how the industry likely would operate under alternative regimes and their implications for asset valuation, electricity pricing, competition, and regulatory requirements.

Tariff Design Methodologies And Policy Issues

- Dr. Hieronymus participated in a series of studies for the National Grid Company of the United Kingdom and for ScottishPower on appropriate pricing methodologies for transmission, including incentives for efficient investment and location decisions.
- For a U.S. utility client, he directed an analysis of time-differentiated costs based on accounting concepts. The study required selection of rating periods and allocation of costs to time periods and within time periods to rate classes.
- For EPRI, Dr. Hieronymus directed a study that examined the effects of time-of-day rates on the level and pattern of residential electricity consumption.
- For the EPRI-NARUC Rate Design Study, he developed a methodology for designing optimum cost-tracking block rate structures.
- On behalf of a group of cogenerators, Dr. Hieronymus filed testimony before the Energy Select Committee of the UK Parliament on the effects of prices on cogeneration development.
- For the Edison Electric Institute (EEI), he prepared a statement of the industry’s position on proposed federal guidelines regarding fuel adjustment clauses. He also assisted EEI in responding to the U.S. Department of Energy (DOE) guidelines on cost-of-service standards.
- For private utility clients, Dr. Hieronymus assisted in the preparation both of their comments on draft FERC regulations and of their compliance plans for PURPA Section l33.
- For a state utilities commission, Dr. Hieronymus assessed its utilities’ existing automatic adjustment clauses to determine their compliance with PURPA and recommended modifications.

- For DOE, he developed an analysis of automatic adjustment clauses currently employed by electric utilities. The focus of this analysis was on efficiency incentive effects.
- For the commissioners of a public utility commission, Dr. Hieronymus assisted in preparation of briefing papers, lines of questioning, and proposed findings of fact in a generic rate design proceeding.

Sales Forecasting Methodologies For Gas And Electric Utilities

- For the White House Sub-Cabinet Task Force on the future of the electric utility industry, Dr. Hieronymus co-directed a major analysis of "least-cost planning studies" and "low-growth energy futures." That analysis was the sole demand-side study commissioned by the task force, and it formed a basis for the task force's conclusions concerning the need for new facilities and the relative roles of new construction and customer side-of-the-meter programs in utility planning.
- For a large eastern utility, Dr. Hieronymus developed a load forecasting model designed to interface with the utility's revenue forecasting system-planning functions. The model forecasts detailed monthly sales and seasonal peaks for a 10-year period.
- For DOE, he directed development of an independent needs assessment model for use by state public utility commissions. This major study developed the capabilities required for independent forecasting by state commissions and provided a forecasting model for their interim use.
- For state regulatory commissions, Dr. Hieronymus has consulted in the development of service area-level forecasting models of electric utility companies.
- For EPRI, he authored a study of electricity demand and load forecasting models. The study surveyed state-of-the-art models of electricity demand and subjected the most promising models to empirical testing to determine their potential for use in long-term forecasting.
- For a Midwestern electric utility, he provided consulting assistance in improving the client's load forecast, and testified in defense of the revised forecasting models.
- For an East Coast gas utility, Dr. Hieronymus testified with respect to sales forecasts and provided consulting assistance in improving the models used to forecast residential and commercial sales.

Other Studies Pertaining To Regulated And Energy Companies

- In a number of antitrust and regulatory matters, Dr. Hieronymus has performed analyses and litigation support tasks. These cases have included Sherman Act Section 1 and 2 allegations, contract negotiations, generic rate hearings, ITC hearings, and a major asset valuation suit. In a major antitrust case, he testified with respect to the demand for business telecommunications services and the impact of various practices on demand and on the market share of a new entrant. For a major electrical equipment vendor, Dr. Hieronymus testified on damages with respect to alleged defects and associated fraud and warranty claims. In connection with mergers for which he is the market power expert, Dr. Hieronymus assists clients in Hart-Scott-Rodino investigations by the Antitrust Division of the U.S. Department of Justice and the Federal Trade Commission. In an arbitration case, he testified as to changed circumstances affecting the equitable nature of a contract. In a municipalization case, he testified concerning the reasonable expectation period for the supplier of power and transmission services to a municipality. In two Surface Transportation Board proceedings, he testified on the sufficiency of product market competition to inhibit the exercise of market power by railroads transporting coal to power plants.
- For a landholder, Dr. Hieronymus examined the feasibility and value of an energy conversion project that sought a long-term lease. The analysis was used in preparing contract negotiation strategies.
- For an industrial client considering development and marketing of a total energy system for cogeneration of electricity and low-grade heat, Dr. Hieronymus developed an estimate of the potential market for the system by geographic area.
- For the U.S. Environmental Protection Agency (EPA), he was the principal investigator in a series of studies that forecasted future supply availability and production costs for various grades of steam and metallurgical coal to be consumed in process heat and utility uses.

TESTIMONY AND REPORTS

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

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PROFESSIONAL HISTORY

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

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Exhibit J-3

Exelon Generation

NERC Region	Balancing Authority/ RTO	Sub region or Zone	Plant Name	Plant / Fuel Type	Total Capacity (MW)	Ownership Share	Ownership Interest (MW)	Long-Term Purchases (Sales) (MW)	Net Interest (MW)
PJM									
RFC	PJM		Braidwood	ST/NUC	2,330	100.00%	2,330	—	2,330
RFC	PJM		Byron	ST/NUC	2,300	100.00%	2,300	—	2,300
RFC	PJM	East	Chester	GT/DFO	39	100.00%	39	—	39
RFC	PJM		Conemaugh	ST/Coal	1,712	20.72%	355	—	355
RFC	PJM	East	Conowingo	HY/WAT	572	100.00%	572	—	572
RFC	PJM	East	Cromby 1	ST/Coal	144	100.00%	144	—	144
RFC	PJM	East	Cromby 2	ST/RFO	201	100.00%	201	—	201
RFC	PJM	East	Croydon	GT/DFO	386	100.00%	386	—	386
RFC	PJM	East	Delaware	GT/DFO	56	100.00%	56	—	56
RFC	PJM		Dresden	ST/NUC	1,734	100.00%	1,734	—	1,734
RFC	PJM	East	Eddystone 1-2	ST/Coal	588	100.00%	588	—	588
RFC	PJM	East	Eddystone 3-4	ST/RFO	760	100.00%	760	—	760
RFC	PJM	East	Eddystone Peakers	GT/DFO	60	100.00%	60	—	60
RFC	PJM	East	Fairless Hills	ST/LFG	60	100.00%	60	—	60
RFC	PJM	East	Falls	GT/DFO	51	100.00%	51	—	51
RFC	PJM		Keystone	ST/Coal	1,711	20.99%	359	—	359
RFC	PJM		La Salle	ST/NUC	2,238	100.00%	2,238	—	2,238
RFC	PJM	East	Limerick	ST/NUC	2,268	100.00%	2,268	—	2,268
RFC	PJM	East	Moser	GT/DFO	51	100.00%	51	—	51
RFC	PJM	East	Muddy Run	PS/WAT	1,070	100.00%	1,070	—	1,070
RFC	PJM	East	Oyster Creek	ST/NUC	619	100.00%	619	—	619
RFC	PJM		Peach Bottom	ST/NUC	2,224	50.00%	1,112	—	1,112
RFC	PJM	East	Pennsbury	GT/LFG	6	100.00%	6	—	6
RFC	PJM		Quad Cities	ST/NUC	1,734	75.00%	1,301	—	1,301
RFC	PJM	East	Richmond	GT/DFO	96	100.00%	96	—	96
RFC	PJM	East	Salem 1-2	ST/NUC	2,304	42.60%	982	—	982
RFC	PJM	East	Salem GT3	GT/KER	38	42.60%	16	—	16
RFC	PJM	East	Schuylkill	GT/RFO	166	100.00%	166	—	166
RFC	PJM	East	Schuylkill	GT/DFO	33	100.00%	33	—	33
RFC	PJM		S.E. Chicago Energy	GT/NG	296	100.00%	296	—	296
RFC	PJM	East	Southwark	GT/DFO	52	100.00%	52	—	52
RFC	PJM		Three Mile Island 1	ST/NUC	786	100.00%	786	—	786
RFC	PJM		Kincaid [1/ (2013)]	ST/Coal	1,108	0.00%	—	1,108	1,108
RFC	PJM		Elwood [1/ (2012)]	GT/NG	750	0.00%	—	750	750
RFC	PJM		Lincoln [1/ (2011)]	GT/NG	576	0.00%	—	576	576
	PJM	East	Grays Ferry Cogeneration [1/ (2017)]	CCNG	150	0.00%	—	150	150
	PJM	East	Montenay Montgomery LP [1/ (2011)]	ST/MSW	28	0.00%		28	28
PJM, Subtotal							21,086	2,612	23,698
		East							8,454
MISO									
SERC	AMIL/MISO		Clinton	ST/NUC	1,043	100%	1,043	—	1,043

Exhibit J-3

Exelon Generation

NERC Region	Balancing Authority/ RTO	Sub region or Zone	Plant Name	Plant / Fuel Type	Total Capacity (MW)	Ownership Share	Ownership Interest (MW)	Long-Term Purchases (Sales) (MW)	Net Interest (MW)
ISO-NE									
NPCC	ISO-NE	Boston	New Boston 1[2/]	ST/NG	—	100.00%	—	—	—
NPCC	ISO-NE	SME	Wyman 4	ST/RFO	603	5.89%	36	—	36
NPCC	ISO-NE	Boston	Framingham Jet	GT/DFO	28	100.00%	28	—	28
NPCC	ISO-NE	Boston	West Medway 1-2	GT/DFO	67	100.00%	67	—	67
NPCC	ISO-NE	RI	West Medway 3	GT/DFO	35	100.00%	35	—	35
NPCC	ISO-NE	Boston	L Street Jet	GT/DFO	12	100.00%	12	—	12
ISO-NE, Subtotal							178	—	178

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Exhibit J-3

Exelon Generation

NERC Region	Balancing Authority/ RTO	Sub region or Zone	Plant Name	Plant / Fuel Type	Total Capacity (MW)	Ownership Share	Ownership Interest (MW)	Long-Term Purchases (Sales) (MW)	Net Interest (MW)
ERCOT									
ERCOT	ERCOT	North	Mountain Creek 6-8	ST/NG	788	100%	788	—	788
ERCOT	ERCOT	North	Mountain Creek 2-3 (Retiring 3/1/09)	ST/NG	86	100%	—	—	—
ERCOT	ERCOT	North	Handley 3-5	ST/NG	1,262	100%	1,262	—	1,262
ERCOT	ERCOT	North	Handley 1-2 (Retiring 3/1/09)	ST/NG	104	100%	—	—	—
ERCOT	ERCOT	Houston	ExTex Laporte	GT/NG	152	100%	152	—	152
ERCOT	ERCOT	North	AES Wolf Hollow [1/ (2023)]	CCNG	350	0%	—	350	350
ERCOT	ERCOT	North	Tenaska/Frontier [1/ (2020), 3/]	CCNG	853	0%	—	853	853
ERCOT, Subtotal							2,202	1,203	3,405
OTHER									
SERC	EES		Tenaska/Frontier [1/ (2020),3/]	CCNG	853	0%	—	853	853
SERC	SOCO		Tenaska Georgia Partners[1/,4/]	GT/DFO	933	0%	—	933	933
SPP	CSWS		Green Country (Jenks) [1/ (2022),5/]	CCNG	795	0%		795	795
OTHER, Subtotal							—	2,581	2,581
Total							24,509	5,543[6/]	30,052

Note: MWs represent summer ratings and are based on ISO/RTO capacity reports (see below) or EIA-860, Energy Information Administration, Annual Electric Generator data.

PJM: EIA-411 - http://www.pjm.com/documents/downloads/reports/2007-pjm-411.xls

ISO-NE: 2008-2017 Forecast Report of Capacity, Energy, Loads, And Transmission, April 2008 — http://www.iso-ne.com/trans/celt/report/2008/2008-celt_report_in_spreadsheet_form.xls

ERCOT: Capacity, Demand and Reserves Report — http://www.ercot.com/news/presentations/2008/2008_Capacity,_Demand,_Reserves_Report_FINAL.xls

1/ Power purchased under a long-term contract. Contract expiration date reflected in parantheses.

2/ New Boston is reported as Retired and/or Deactivated in ISO-NE capacity reports.

3/ The capacity rating reported here represents the unit rating reported by ERCOT. The contractual tolled amount is 830 MW. Frontier is interconnected to both Entergy and ERCOT transmission systems. 300 MW of the output of this facility is sold to Entergy

4/ The capacity rating reported here represents the unit rating reported by EIA. Exelon has a tolling agreement with respect to this facility. The contractual tolled amount is 942 MW. Starting June 1, 2010, Exelon has agreed to sell its rights under the to

5/ The capacity rating reported here represents the unit rating reported by EIA. Exelon has a tolling agreement with respect to this facility. The contractual tolled amount is 785 MW. 200 MW of the output of this facility is sold to Southwestern Public

6/ Adjusted to eliminate double-counting of the PPA with respect to the Frontier facility, which is interconnected to both ERCOT and EES.

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Exhibit J-4

NRG Energy Generation

NERC Region	Balancing Authority/ RTO	Sub region	Plant Name	Plant / Fuel Type	Total Capacity (MW)	Ownership Share	Ownership Interest (MW)	Long-Term Purchases (Sales) (MW)	Net Interest (MW)
ISO-NE									
NPCC	ISO - NE	SWCT	Branford	GT/KER	15.8	100%	15.8	—	15.8
NPCC	ISO - NE	NOR	Cos Cob	GT/KER	90.2	100%	90.2	—	90.2
NPCC	ISO - NE	SWCT	Devon	GT/KER	134.6	100%	134.6	—	134.6
NPCC	ISO - NE	CT	Franklin Drive	GT/KER	15.4	100%	15.4	—	15.4
NPCC	ISO - NE	CT	Middletown 10 (RMR)	GT/KER	17.1	100%	17.1	—	17.1
NPCC	ISO - NE	CT	Middletown 2-4 (RMR)	ST/RFO	753.0	100%	753.0	—	753.0
NPCC	ISO - NE	CT	Montville (RMR)	ST/RFO	493.7	100%	493.7	—	493.7
NPCC	ISO - NE	NOR	Norwalk Harbor 1-2 (RMR)	ST/RFO	330.0	100%	330.0	—	330.0
NPCC	ISO - NE	NOR	Norwalk Harbor 10	GT/KER	11.9	100%	11.9	—	11.9
NPCC	ISO - NE	SEMA	Somerset 6	ST/Coal	109.1	100%	109.1	—	109.1
NPCC	ISO - NE	SEMA	Somerset Jet 2	GT/KER	17.2	100%	17.2	—	17.2
NPCC	ISO - NE	CT	Torrington	GT/KER	15.6	100%	15.6	—	15.6
NPCC	ISO - NE	SWCT	Devon (2010)	GT/KER	200.0	50%	100.0	—	100.0
NPCC	ISO - NE	SWCT	Middletown (2011)	GT/KER	200.0	50%	100.0		100.0
ISO-NE, Subtotal							2,203.6	—	2,203.6
NYISO									
NPCC	NYISO	J	Arthur Kill GT1	GT/KER	11.6	100%	11.6	—	11.6
NPCC	NYISO	J	Arthur Kill ST2-3	ST/NG	855.9	100%	855.9	—	855.9
NPCC	NYISO	J	Astoria	GT/NG	573.5	100%	573.5	—	573.5
NPCC	NYISO	A	Dunkirk	ST/Coal	556.5	100%	556.5	—	556.5
NPCC	NYISO	A	Huntley	ST/Coal	384.5	100%	384.5	—	384.5
NPCC	NYISO	C	Oswego	ST/RFO	1,669.0	100%	1,669.0	—	1,669.0
NYISO, Subtotal							4,051.0	—	4,051.0

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Exhibit J-4

NRG Energy Generation

NERC Region	Balancing Authority/ RTO	Sub region	Plant Name	Plant / Fuel Type	Total Capacity (MW)	Ownership Share	Ownership Interest (MW)	Long-Term Purchases (Sales) (MW)	Net Interest (MW)
PJM									
RFC	PJM	East	Dover Energy	GT/NG	104.1	100%	104.1	—	104.1
RFC	PJM		Paxton Creek	IC/NG	12.0	100%	12.0	—	12.0
RFC	PJM	East	Vienna	ST/RFO	144.0	100%	144.0	—	144.0
RFC	PJM	East	Vienna	GT/DFO	14.0	100%	14.0	—	14.0
RFC	PJM		Conemaugh	ST/Coal	1,711.5	3.72%	63.7	—	63.7
RFC	PJM		Keystone	ST/Coal	1,711.0	3.70%	63.3	—	63.3
RFC	PJM		Rockford Energy Center	GT/NG	447.4	100%	447.4	—	447.4
RFC	PJM	East	Indian River 3-4,10	ST/Coal/GT	617.0	100%	617.0	—	617.0
RFC	PJM	East	Indian River 1-2 (Retiring, 2010-11)	ST/Coal	179.0	100%	179.0	—	179.0
PJM, Subtotal							1,644.5	—	1,644.5
SERC									
SERC	EES/LAGN		Bayou Cove	GT/NG	300.0	100%	300.0	—	300.0
SERC	EES/LAGN		Big Cajun 1 1-2	ST/NG	220.0	100%	220.0	—	220.0
SERC	EES/LAGN		Big Cajun 1 3-4	GT/NG	210.0	100%	210.0	—	210.0
SERC	EES/LAGN		Big Cajun 2	ST/Coal	1,730.0	86.04%	1,488.5	—	1,488.5
SERC	EES/LAGN		Sterlington	GT/NG	176.0	100%	176.0	—	176.0
SERC	EES/LAGN		Cottonwood (Toll)	CC/NG	—	0%	—	600.0	600.0
SERC, Subtotal							2,394.5	600.0	2,994.5
WECC									
WECC	CAISO		El Segundo	CC/NG	670.0	100%	670.0	—	670.0
WECC	CAISO		Encina (Cabrillo I) (Black Start) 1/	GT/NG	14.5	100%	14.5	(15)	—
WECC	CAISO		Encina (Cabrillo I) (Dual Fuel) 1/	ST/NG	950.0	100%	950.0	(950)	—
WECC	CAISO		Cabrillo II (RMR)	GT/NG	189.0	100%	189.0		189.0
WECC	CAISO		Long Beach 2/	GT/NG	260.0	100%	260.0	(260)	—
WECC	CAISO		El Segundo II (2011) 2/	ST/NG	550.0	100%	550.0	(550)	—
WECC	NEVP		Saguaro 3/	ST/NG	101.0	50%	50.5	(50.5)	—
WECC, Subtotal							2,684.0	(1,825.0)	859.0
ERCOT									
ERCOT	ERCOT	Houston	Cedar Bayou 1 and 2	ST/NG	1,492.0	100%	1,492.0	—	1,492.0
ERCOT	ERCOT	Houston	Cedar Bayou 3 (Retired)	ST/NG	—	100%	—	—	—
ERCOT	ERCOT	Houston	Cedar Bayou 4 (2009)	ST/NG	544.0	50%	272.0	—	272.0
ERCOT	ERCOT	Houston	Greens Bayou 5	ST/NG	398.0	100%	398.0	—	398.0
ERCOT	ERCOT	Houston	Greens Bayou 73-84	GT/NG	305.0	100%	305.0	—	305.0
ERCOT	ERCOT	North	Limestone	ST/Coal	1,689.0	100%	1,689.0	—	1,689.0
ERCOT	ERCOT	Houston	San Jacinto	GT/NG	164.0	100%	164.0	—	164.0
ERCOT	ERCOT	South	South Texas Project	ST/NUC	2,564.0	44%	1,128.2	—	1,128.2

Exhibit J-4

NRG Energy Generation

NERC Region	Balancing Authority/ RTO	Sub region	Plant Name	Plant / Fuel Type	Total Capacity (MW)	Ownership Share	Ownership Interest (MW)	Long-Term Purchases (Sales) (MW)	Net Interest (MW)
ERCOT	ERCOT	West	Sherbino Wind (2009)	WT/WND	150.0	50%	75.0	—	75.0
ERCOT	ERCOT	West	Elbow Creek Wind (2009)	WT/WND	117.3	100%	117.3	—	117.3
ERCOT	ERCOT	Houston	S.R.Bertron 3-4	GT/NG	446.0	100%	446.0	—	446.0
ERCOT	ERCOT	Houston	S.R.Bertron 1-2	ST/NG	379.0	100%	379.0	—	379.0
ERCOT	ERCOT	Houston	T.H. Wharton CCs	CC/NG	679.0	100%	679.0	—	679.0
ERCOT	ERCOT	Houston	T.H. Wharton GTs	GT/NG	354.0	100%	354.0	—	354.0
ERCOT	ERCOT	Houston	W.A. Parish 1-4	ST/NG	1,099.0	100%	1,099.0	—	1,099.0
ERCOT	ERCOT	Houston	W.A. Parish 5-8	ST/Coal	2,472.0	100%	2,472.0	—	2,472.0
ERCOT	ERCOT	Houston	W.A. Parish GT1	GT/NG	13.0	100%	13.0	—	13.0
ERCOT	ERCOT	Houston	P H Robinson (Mothballed)	ST/NG	2,187.0	100%	2,187.0	—	2,187.0
ERCOT, Subtotal							13,269.5	—	13,269.5
TOTAL							**26,247.1**	**(1,225.0)**	**25,022.1**

Exhibit J-4

NRG Energy Generation

Notes:

Note: MWs represent summer ratings and are based on ISO/RTO capacity reports (see below) or EIA-860, Energy Information Administration, Annual Electric Generator data.

PJM: EIA-411 - http://www.pjm.com/documents/downloads/reports/2007-pjm-411.xls

ISO-NE: 2008-2017 Forecast Report of Capacity, Energy, Loads, And Transmission, April 2008 — http://www.iso-ne.com/trans/celt/report/2008/2008-celt_report_in_spreadsheet_form.xls

NYISO: 2008 Load and Capacity Data — http://www.nyiso.com/public/webdocs/services/planning/planning_data_reference_documents/2008_NYCA_Generators.xls

ERCOT: Capacity, Demand and Reserves Report — http://www.ercot.com/news/presentations/2008/2008_Capacity,_Demand,_Reserves_Report_FINAL.xls

CAISO: Generation Capability List as of 27-Jun-2008 — http://www.caiso.com/14d4/14d4c4ff59780.html ISO-NE RMR data from http://www.iso-ne.com/genrtion_resrcs/reports/rmr/reliability_agreeement_status_summary.ppt#259,2,Reliability Agreements CAISO RMR and Black Start Agreement data from http://www.caiso.com/204c/204c7a1119bb0.pdf

1/ Cabrillo I (Encina Units 1-5 and CT) were previously subject to RMR contracts with CAISO. As of January 1, 2008, these were replaced with a Black Start Agreement on the CT, and a Dual Fuel Agreement on the remaining units. There is also a long-term toll

2/ Power sold to Southern California Edison under a long-term (10-year) contract.

3/ Power sold to Nevada Power Company through 2022, and to two steam hosts with contracts ending in 2009 and 2015.

MODELING AND DATA INPUTS

CASm is a linear programming model developed specifically to perform the calculations required in undertaking the delivered price test. The model includes each potential supplier as a distinct entity that is connected via a transportation (or "pipes") representation of the transmission network. Each link in the network has its own non-simultaneous limit and cost. Potential suppliers are allowed to use all economically and physically feasible links or paths to reach the destination market. In instances where more generation meets the economic facet of the delivered price test than can actually be delivered on the transmission network, scarce transmission capacity is allocated based on the relative amount of economic generation that each party controls at a constrained interface. The model can also incorporate Simultaneous Import Limits ("SILs").

The competitive analysis screen was conducted using the existing market structure and publicly available data on generation and transmission capacity. The data inputs were adjusted to reflect 2009 conditions as a representative year (*e.g.*, to reflect updated fuel prices, load, and generation). A complete set of the input data used in the analysis is contained in workpapers. A summary of these inputs is provided in Exhibit J-1 and below.

A. Regions Modeled

I included as potential suppliers all entities within three wheels of the relevant balancing authority areas.[1] The model includes all significant generation and load sources, including traditional utilities, non-utility and merchant generators, municipal utilities and cooperatives. Each entity is generally modeled as an individual "node."[2] For most of the regions included in the model, including the relevant regional transmission organizations ("RTOs"), balancing authority areas were used to aggregate generation and transmission assets.

1 This list was selected in recognition of the Commission's guidance regarding the number of wheels a potential supplier can realistically travel and still be considered a player in the destination market. For example, in *FirstEnergy*, the Commission limited the number of wheels "a supplier could reasonably travel to reach the destination market," recognizing that "[m]ore distant suppliers would face considerable losses and transmission costs." The Commission limited the potential suppliers to those within four wheels. *Ohio Edison Co.*, 80 FERC ¶ 61,039, *reh'g denied*, 81 FERC ¶ 61,109 (1997), *reh'g denied*, 85 FERC ¶ 61,203 (1998).

Also, the request for comments on the use of computer models in merger analysis suggests that "three wheels has been deemed adequate." Inquiry Concerning the Commission's Policy on the Use of Computer Models in Merger Analysis, Notice of Request for Written Comments and Intent to Convene a Technical Conference, Docket No. PL98-6-000, April 16, 1998, at 24.

2 The term "node" is used in CASm to denote a region or bubble where load, generation, or transmission assets are aggregated. Potential suppliers who own generation at more than one transmission point have generation in more than one node. In CASm, the affiliated nodes are aggregated to determine the relevant market metrics.

B. Generating Resources

The main sources for data on generating plant capability are the EIA-860 and EIA-411 reports published in 2007 and 2008, supplemented by earlier editions as necessary and data from Ventyx's Energy Velocity.[3] These data sources provide information on capacity (nameplate and seasonal (summer and winter) net dependable capacity ("NDC") ratings), planned retirements and additions, primary and secondary fuel, and ownership, including jointly-owned units. NDC ratings were used for the analyses, with the summer ratings used for the shoulder time periods. Planned retirements and capacity additions were reflected in the analysis, as described below. For jointly-owned plants, shares were assigned to each of the respective owners. The capacity representing shares of jointly-owned units was "moved" in most regions of the model from its actual physical location to the geographic location of the owner because I assume that there is firm transmission to the owner's balancing authority area.

Each supplier's generating resources were adjusted to reflect long-term (one year or more) capacity purchases and sales where they could be identified from publicly available data.[4] The capacity representing firm purchases and sales, analogous to the treatment of jointly-owned units, was "moved" in the model from its actual physical location to the geographic location of the buyer. Generation ownership was adjusted to reflect the transfer of control by assuming that the sale resulted in a decrease in capacity for the seller and a corresponding increase in capacity for the buyer.[5] Consistent with guidance provided in Appendix A, it was assumed that system power sales were comprised of the lowest-cost supply for the seller unless a more representative price could be

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3 Energy Velocity is one of Ventyx's set of databases and forecasts. It is widely used in the industry. In ERCOT, the generating facilities capacity and zonal location are based on information from Energy Velocity as well as an ERCOT annual planning report (Report on the Capacity, Demand and Reserves in the ERCOT Region, available at: http://www.ercot.com/news/presentations/2008/2008_Capacity,_Demand,_Reserves_Report_FINAL.xls)

4 Sources for such information include FERC Form 1 and EIA Forms 411 and 412, utility resource plans and NERC's Electricity Supply and Demand database (as complied by Energy Velocity). Requirements contracts are treated as the equivalent of native load and potential suppliers' Economic Capacity was not adjusted to reflect them.

5 The Revised Filing Requirements direct applicants to consider whether operational control of a unit is transferred to the buyer. Such information generally is not readily available for non-applicants. Therefore, I treated long-term sales as being under the control of the purchaser.

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identified.[6] Public data on purchases and sales, however, are not entirely complete or consistent across sources. In any event, adjustments to generating capacity for long-term sales and purchases is primarily relevant for Exelon and NRG and their affiliates and are detailed in Exhibit J-1.

Because the delivered price test is intended to evaluate energy products, seasonal capacity was de-rated to approximate the actual availability of the units in each period. That is, it was assumed that generation capacity would be unavailable during some hours of the year for either (planned) maintenance or forced (unplanned) outages. Data reported in the NERC "Generating Availability Data System" ("GADS") were used to calculate the "average equivalent availability factor" to estimate total outages, and the "average equivalent forced outage rate" to estimate forced outages for fossil and nuclear plants.[7] Based on a review of PJM, ERCOT and CSWS historical planned outages (as reported in the FERC Form 714), scheduled maintenance was assumed to occur mostly in the shoulder season (80 percent), with the remainder scheduled during the winter season. Forced outages were assumed to occur uniformly throughout the year.

Supply curves were developed for each potential supplier in the model, based on estimates of each unit's incremental costs. The incremental cost is calculated by multiplying the fuel cost for the unit by the unit's efficiency (heat rate) and adding any additional variable costs that may apply, such as costs for variable operations and maintenance ("O&M") and costs for environmental controls.[8]

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6 "[T]he lowest running cost units are used to serve native load and other firm contractual obligations" (Order No. 592 at 30,132). The lowest-cost supply that was available year-round (*i.e.*, excluding hydro) was used. To the extent that long-term sales could be identified specifically as unit sales, the capacity of the specific generating unit was adjusted to reflect the sale, and the variable element of the purchase price attributed to the sale was the variable cost of the unit.

7 GADS reported data from 2003-2007 was used in most instances. In addition to thermal unit availability, hydro unit availability and generation are specified for each time period. For each of the time periods analyzed, hydro capacity factors have been assigned to each unit based on historical operation. Capacity factors for hydro units were based on five years of Form 759 monthly generation data (2003-2007), reported maximum capacities and, where necessary, assumptions regarding minimum capacity (assumed to be 15 percent of maximum if no data is available).

8 PURPA-related generators (*i.e.*, QFs and small power producers) were generally assumed to be must-run and the variable costs set to zero absent additional information from regulatory filings.

Data used to derive incremental cost estimates for each unit were taken from the following sources:

- Heat Rates – EIA Form 860, supplemented by data reported in Energy Velocity's database. (Note that the most recently available data from the Form 860 date back to 1995.) [9]
- Fuel Costs - Futures prices and Regional Projections. Regional dispatch costs for natural gas and oil units were derived from futures market data and spot price history (2007 and 2008 data, retrieved in November 2008). For gas-fired units, I relied on 2009 NYMEX Henry Hub natural gas futures contract prices and applied regional basis differentials. I used these data to estimate regional delivered commodity prices for all gas-fired units modeled. Basis differentials were estimated from a review of regional market center and Henry Hub prices from EIA. The NYMEX Henry Hub price, plus each region's basis differential equals my estimated regional price. For oil-fired units, I relied on the NYMEX futures contract for light sweet crude oil. I estimated delivered residual and distillate oil prices based on a multi year analysis of delivered refined products versus spot crude oil prices. I used plant specific forecasts of coal prices (from FERC Form 423 supplemented by Energy Velocity Spot prices) as the basis for my coal unit dispatch cost and escalated to 2009 using information in EIA's 2008 Annual Energy Outlook (table 15). In instances where no forecast was available for a given unit, I used regional average price estimate as my default.
- Variable O&M – $1/MWh for gas and oil steam units, $3/MWh for scrubbed coal-fired units and $2/MWh for other coal-fired units (generic estimates based on trade and industry sources). Additional Variable O&M adders for other unit types are shown in my workpapers. As noted, these variable O&M costs are generic estimates by plant type and do not necessarily match actual individual unit O&M costs. Notably, variable O&M accounts for a minor portion of the dispatch costs used in the analysis, and, importantly, the specific O&M assumption tends not to alter the merit order of the generic types of generation.
- Environmental Costs – All units covered by Phase II of the Clean Air Act Amendments of 1990 (CAAA) are assessed a variable dispatch adder to cover costs associated with SO_2 emissions. This unit-specific cost is calculated using the SO_2 content of fuel burned at the unit as reported in FERC Form 423 (adjusting for emissions reduction equipment at the facility) and an SO_2

9 For combined-cycle units, Energy Velocity provides information on the combined-cycle and peaking (*e.g.*, duct firing) modes of operation and I have incorporated this information where available. In the Eastern Interconnection, new merchant and utility capacity included in the analysis was priced assuming an average full-load heat rate of 10,000 Btu/kWh for combustion turbines and 7,000 Btu/kWh for combined cycle plants absent more specific information. These values were derived from an evaluation of existing technology and are consistent with the default assumptions used in Energy Velocity for these types of units. In ERCOT, heatrates for all units were taken from Energy Velocity. In both regions, Variable O&M costs for new units were assumed to be the same as for existing units.

allowance cost of $154/ton for 2009.[10] In addition to SO_2, the unit dispatch costs also reflect the impact of existing NOx trading programs in the Northeast (OTR). Unit-specific data on NOx rates (lbs/mmBtu) were taken from the EPA's "2000 Acid Rain Program Emission Scorecard."[11] The NOx allowance price for the OTR was assumed to be $550/ton.[12]

C. Load Data

Loads, which are used in the Available Economic Capacity measure, were aggregated to match the ten time periods analyzed. Hourly load data from 2007 FERC Form 714 filings was generally used as the basis for each entity's load obligation. The loads were then escalated to 2009 based on the respective load forecasts from the FERC Form 714s. The development of the Available Economic Capacity measure in PJM is described in Exhibit J-1. For the analysis in CSWS, I shaped loads in the model based on CSW's historical data.[13]

D. Transmission

The Commission's Appendix A analysis specifies that the transmission system be modeled on the basis of inter-balancing authority area transmission capability using transmission prices based on transmission providers' maximum non-firm OATT rates, except where lower rates can be clearly documented. This dictates a transportation representation of the transmission network, and the structure of CASm was designed to conform to Appendix A. This representation remains appropriate for some regions in the United States (*i.e.*, those where transmission service is still generally provided under each transmission owner's OATT), such as in the Southeast. Basing tariffs on OATT rates is increasingly modified by RTO transmission pricing arrangements,

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10 Consistent with my methodology for estimating coal prices, I used plant specific forecasts of SO_2 emissions as the basis for my coal unit dispatch cost. When there was no forecast for a given unit, I defaulted to regional average SO_2 estimate. SO_2 costs are from Evolution Markets LLC's Monthly Market Update - SO_2 Markets, as of December 4th 2008.

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

12 NOx rates were derived from EPA's 2000 Acid Rain Program Emission Scorecard and NOx allowance price is from Evolution Markets LLC's Monthly Market Update - NOx Markets, as of December 4th 2008.

13 When evaluating the Available Economic Capacity measure in the CSWS market, I applied load for entities in relevant portion of the Eastern Interconnection, but did not include loads for entities located inside ERCOT (such that all economic generation in ERCOT was available to compete for transmission capacity into CSWS).

however, and the Commission has instructed applicants to account for them.[14] As discussed below, I incorporated the RTO arrangements in my modeling of transmission rates and limits and have also explicitly incorporated SILs into my modeling assumptions.

For the PJM and CSWS analyses, transmission capability was taken primarily from postings on the Open Access Same-Time Information System ("OASIS"). OASIS reports Total Transmission Capability ("TTC"), firm Available Transmission Capability ("ATC") and non-firm ATC. Data generally are provided monthly for a twelve-month period starting with the next month. I have used monthly non-firm ATC postings from OASIS for the Southeast interconnections. I used the New York ISO 2009 IRM requirements study as the basis for the Northeast interconnections, as described in Exhibit J-1.[15] For other regions where transmission is no longer posted on a balancing authority area to balancing authority area basis, I have generally used TTC values from older filings or used information from other sources, although I would note that the assumption on transmission capacity in the regions outside of PJM has an insignificant impact on the results of my analyses. Given that I apply a SIL into the PJM and CSWS markets, the specific assumption on balancing authority area to balancing authority area limits has little impact because the overall amount of rival capacity into the markets is limited by the SIL.

For the ERCOT analyses, I used a zonal configuration as described in Exhibit J-1. ERCOT provides information on commercially significant constraints in 15 minutes increments, that I used to model the inter-zonal transfer capabilities.[16] I also modeled the 2 DC ties to ERCOT from CFE and SPP with ratings from "NERC 2008 regional study" as described in Exhibit J-1. For the CSWS market, I used SILs from Oklahoma Gas and Electric's recent filing in connection with their acquisition of the Redbud facility.[17]

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14 *See Revised Filing Requirements Under Part 33 of the Commission's Regulations*, Order No. 642, FERC Stats. & Regs. [Regs. Preambles July 1996-Dec. 2000] ¶ 31,111 at 31,890 (2000), *on reh'g*, Order No. 642-A, 94 FERC ¶ 61,289 (2001). ("Revised Filing Requirements" or "Order No. 642").

15 For the PJM Classic market, I used the transmission values shown in the New York ISO 2009 IRM requirements study as well as the maximum historical limit reported by PJM on the AP South interface.

16 ERCOT does not report information on transmission limits and flows from the Houston to North zone. I assumed that the limit was the same as that posted from North to Houston.

17 The Commission conditionally accepted Oklahoma Gas and Electric's application September 16, 2008. *Oklahoma Gas and Electric Company* 124 FERC ¶ 61,239 (2008).

A summary of the transmission data, including the various SILs applied, is provided in workpapers.

Consistent with Order No. 592, the ceiling rates in Schedule 8 (Non-Firm Point-to-Point Transmission Service) of each utility's Order No. 888 filings were used for utilities that are not part of RTO arrangements.[18] In many instances, utilities report both on-peak and off-peak ceiling rates in its Order No. 888 filing. If so, the applicable transmission rates for the on- and off-peak periods were used. If not, the filed ceiling rate was applied for all periods. Ancillary service charges from Schedules 1 (Scheduling, System Control and Dispatch Service) and 2 (Reactive Supply and Voltage Control from Generation Sources Service) of Order No. 888 filings were added where applicable to determine the final rates. For the RTOs, I have used information on their respective OASIS sites to calculate the applicable transmission rates.

Losses, which are assumed to be 2 percent based on information in Energy Velocity, are assessed for each wheel incurred along the path to deliver power to the destination market but are not added for the final wheel into the destination market.

E. Allocation of Limited Transmission

Appendix A notes that there are various methods for allocating transmission, and that applicants should support the method used.[19] For purposes of this analysis, limited transmission capacity was allocated using a prorata "squeeze-down" method, so-named because it seeks to prorate capacity at each node and is the closest approximation to what the Commission applied in *FirstEnergy*[20] that is computationally feasible. Under this method, shares of available transmission

18 In instances where transmission data were not reported in dollars per MWh, the $/MW rates were converted to $/MWh rates using the "Appalachian" method. *Appalachian Power Co.*, 39 FERC ¶ 61,296 at 61,965 (1987). If instances when data was not available, I assumed default transmission rates of $2/MWh and $1/MWh for peak and off-peak periods, respectively.

19 *See Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement*, Order No. 592, FERC Stats. & Regs.[Regs. Preambles 1996-2000] ¶ 31,044 at 30,133(1996) ("Merger Policy Statement" or "Order No. 592") ("In many cases, multiple suppliers could be subject to the same transmission path limitation to reach the same destination market and the sum of their economic generation capacity could exceed the transmission capability available to them. In these cases, the ATC must be allocated among the potential suppliers for analytic purposes. There are various methods for accomplishing this allocation. Applicants should support the method used."), *reconsideration denied*, Order No. 592-A, 79 FERC ¶ 61,321 (1997).

20 Ohio Edison Co. at 61,106-07: "When there was more economic capacity (or available economic capacity) outside of a transmission interface than the unreserved capability would allow to be delivered into the destination market, the transmission capability was allocated to the suppliers in proportion to the amount of economic capacity each supplier had outside the interface."

are allocated at each interface, diluting the importance of distant capacity as it gets closer to the destination market. When there is economic supply (*i.e.*, having a delivered cost less than 105 percent of the destination market price) competing to get through a constrained transmission interface into a control area, the transmission capability is allocated to the suppliers in proportion to the amount of economic supply each supplier has outside the interface.

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

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

F. Historical Purchases and Sales

Included in workpapers is information on historical purchases and sales. Specifically, FERC's Electronic Quarterly Report database was queried to obtain all of Exelon's and NRG's, including their affiliates', sales from 2006 through quarter 3, 2008. In the markets where Exelon and NRG both reported sales, the total volume of sales for those delivery point were also queried so that Exelon's and NRG's market shares could be calculated.[21] Also included in workpapers are historical purchases and sales from FERC Form 1, compiled by Energy Velocity, for 2006 and 2007 (the most recent two years of data available). Note that the information provided on the annual form is not as detailed as the information provided in the EQRs. For example, purchases reported in the FERC Form 1 do not specify where transactions were made, whereas this information is available in the EQR data.

Historical capacity factors were obtained from information from the EPA's Continuous Emissions Monitoring System ("CEMs"), as compiled by Energy Velocity. Hourly values for specific Exelon, NRG and competing generators were obtained for the most recent 12 month period. These data are provided in workpapers.

21 Many companies report sales from an entity to an affiliated power marketing company. To avoid double counting sales, data obtained from the EQR database were modified to exclude these affiliated sales.

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COMPETITIVE ANALYSIS SCREENING MODEL (CASm)

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

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

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

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

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

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

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

The following sections describe:

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

INPUT DATA

Market Participants

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

Nodes

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

Output Capability

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

Destination Market Prices

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

Interconnections

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

Lines

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

Scenarios

The final input area for CASm is related to scenario definition. Scenarios define which parties are considering merging, which load periods are relevant, and so on. In effect, the scenarios define a number of individual analyses to be performed, and how they should be compared to each other for reporting purposes. CASm can solve scenarios either as separate LP programs or, in instances where there are no changes in the underlying data or network, CASm can solve a single scenario and then calculate the changes “virtually” using the underlying results of the initial scenario. When solving separate pre and post scenarios, CASm uses the same decisions in the post scenario as in the pre scenario, although there may be slight differences if the model can find two alternative solutions that meet the LP’s requirements.

Accounting for Ownership

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

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REQUIRED CALCULATIONS

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

- **Economic Capacity** is the amount of capacity that can reach a market at a cost (including transmission rates, transmission losses and ancillary services) no more than 105 percent of the destination market price.
- **Available Economic Capacity** is the amount of Economic Capacity that is available after serving native load and other net firm commitments with the lowest cost units.

For every analysis, the following process is undertaken:

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

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

Economic Capacity

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

minimize cost for supplies at the destination market

subject to:

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

supply < quantity, for each node and tranche

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

line flows are adjusted for losses, for all interconnections

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

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

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

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

minimize cost for supplies at the destination market; and

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

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

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

Available Economic Capacity

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

minimize cost for supplies at the destination market

subject to:

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

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

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

line flows are adjusted for losses, for all interconnections

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

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

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

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

When transmission capacity is to be prorated the objective becomes:

minimize cost for supplies at the destination market; and

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

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

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

OUTPUTS

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

- Supplied MW
- Market Share
- HHIs

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

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

“SQUEEZE-DOWN” PRORATION

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

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

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

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

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

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

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

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

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

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

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

8. To the extent an iteration of the algorithm does not resolve any additional nodes and the destination market has not yet been reached (i.e., a loop is detected), flow is disallowed from any unresolved node to the furthest and smallest node affected by a loop.
9. The proration has been completed when the destination market node has been resolved. At that point, the "shares" at the destination market represent the prorated shares of deliverable energy.
10. If ownership at a node is to be "imputed," or credited to another node, further proration targets are calculated. First, only those tranches that can deliver to the destination within 105% of the market price are considered. A factor representing the share each owner has of these economic tranches is calculated. For each owner, a constraint is calculated that limits the sum of injections attributed to that owner to be not more than that owner's "share" of the target calculated above. In this way, the proportion of ownership of economic capacity at a node is fairly reflected in the final solution outcome.
11. Injections for each supplier are "capped" at the calculated shares, and these injections are then checked for economic feasibility. While suppliers need not deliver their energy to the destination in exactly the way that their share was calculated, the solution is still both economically and physically feasible. The final solution represents the least-cost method of delivering these supplies.

CASM IMPLEMENTATION

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

Exhibit J-7

Exelon-NRG Merger: DPT Results in PJM (Pre-Mitigation)

PJM - Economic Capacity

			Pre-Merger						Post-Merger (Pre-Mitigation)			
			Exelon		NRG							
Market	Period	Price	MW	Mkt Share	MW	Mkt Share	Market Size	HHI	MW	Mkt Share	HHI	HHI Chg
PJM	S_SP1	$250	23,961	14.5%	1,604	1.0%	165,368	790	25,565	15.5%	818	28
PJM	S_SP2	$160	23,197	14.4%	1,602	1.0%	161,314	798	24,799	15.4%	827	29
PJM	S_P	$ 90	21,669	14.3%	1,413	0.9%	151,602	817	23,082	15.2%	843	27
PJM	S_OP	$ 50	18,051	15.7%	999	0.9%	114,772	1,009	19,050	16.6%	1,036	27
PJM	W_SP	$105	21,460	14.1%	1,327	0.9%	151,769	765	22,788	15.0%	790	25
PJM	W_P	$ 75	18,841	14.2%	1,283	1.0%	132,677	811	20,124	15.2%	839	27
PJM	W_OP	$ 50	16,608	15.5%	896	0.8%	107,527	908	17,504	16.3%	933	26
PJM	SH_SP	$100	19,774	14.7%	1,227	0.9%	134,551	820	21,002	15.6%	847	27
PJM	SH_P	$ 70	15,903	14.5%	1,211	1.1%	109,931	905	17,114	15.6%	937	32
PJM	SH_OP	$ 45	15,463	17.4%	854	1.0%	88,781	1,062	16,317	18.4%	1,095	34

PJM Classic - Economic Capacity

			Pre-Merger						Post-Merger (Pre-Mitigation)			
			Exelon		NRG							
Market	Period	Price	MW	Mkt Share	MW	Mkt Share	Market Size	HHI	MW	Mkt Share	HHI	HHI Chg
PJM MAAC	S_SP1	$250	11,094	13.6%	1,349	1.7%	81,473	807	12,443	15.3%	852	45
PJM MAAC	S_SP2	$200	11,094	13.6%	1,350	1.7%	81,345	808	12,444	15.3%	853	45
PJM MAAC	S_P	$100	8,804	12.3%	1,176	1.7%	71,449	775	9,980	14.0%	816	41
PJM MAAC	S_OP	$ 55	7,699	13.0%	1,053	1.8%	59,093	803	8,752	14.8%	850	46
PJM MAAC	W_SP	$115	9,454	13.4%	1,041	1.5%	70,806	788	10,495	14.8%	827	39
PJM MAAC	W_P	$ 85	7,911	12.4%	928	1.5%	63,759	781	8,839	13.9%	818	36
PJM MAAC	W_OP	$ 60	6,987	12.4%	922	1.6%	56,289	788	7,908	14.1%	828	41
PJM MAAC	SH_SP	$105	8,987	13.6%	1,006	1.5%	66,322	776	9,994	15.1%	817	41
PJM MAAC	SH_P	$ 80	7,101	12.2%	897	1.5%	58,365	767	7,998	13.7%	804	37
PJM MAAC	SH_OP	$ 55	6,719	13.0%	904	1.8%	51,694	756	7,623	14.8%	801	45

PJM East - Economic Capacity

			Pre-Merger						Post-Merger (Pre-Mitigation)			
			Exelon		NRG							
Market	Period	Price	MW	Mkt Share	MW	Mkt Share	Market Size	HHI	MW	Mkt Share	HHI	HHI Chg
PJM East	S_SP1	$250	9,296	20.8%	1,116	2.5%	44,711	1,088	10,411	23.3%	1,192	104
PJM East	S_SP2	$200	9,298	20.8%	1,116	2.5%	44,647	1,090	10,414	23.3%	1,194	104
PJM East	S_P	$100	7,065	18.5%	948	2.5%	38,131	955	8,012	21.0%	1,047	92
PJM East	S_OP	$ 60	6,033	18.7%	910	2.8%	32,273	930	6,944	21.5%	1,036	105
PJM East	W_SP	$120	7,908	20.2%	845	2.2%	39,067	1,012	8,753	22.4%	1,099	88
PJM East	W_P	$ 90	6,573	18.3%	834	2.3%	35,856	940	7,407	20.7%	1,025	85
PJM East	W_OP	$ 65	5,554	17.9%	811	2.6%	31,029	883	6,365	20.5%	977	94
PJM East	SH_SP	$110	7,716	20.5%	823	2.2%	37,578	975	8,539	22.7%	1,064	90
PJM East	SH_P	$ 80	5,908	17.6%	813	2.4%	33,513	880	6,721	20.1%	965	86
PJM East	SH_OP	$ 55	5,522	19.1%	803	2.8%	28,924	867	6,326	21.9%	973	106

Exhibit J-8

Exelon-NRG Merger: DPT Results (Post-Mitigation)

PJM East - Economic Capacity

			Pre-Merger						Post-Merger (Pre-Mitigation)			
			Exelon		NRG							
Market	Period	Price	MW	Mkt Share	MW	Mkt Share	Market Size	HHI	MW	Mkt Share	HHI	HHI Chg
PJM East	S_SP1	$250	9,296	20.8%	1,116	2.5%	44,711	1,088	9,403	21.0%	1,097	9
PJM East	S_SP2	$200	9,298	20.8%	1,116	2.5%	44,647	1,090	9,406	21.1%	1,099	9
PJM East	S_P	$100	7,065	18.5%	948	2.5%	38,131	955	7,165	18.8%	963	8
PJM East	S_OP	$ 60	6,033	18.7%	910	2.8%	32,273	930	6,097	18.9%	937	7
PJM East	W_SP	$120	7,908	20.2%	845	2.2%	39,067	1,012	8,001	20.5%	1,021	9
PJM East	W_P	$ 90	6,573	18.3%	834	2.3%	35,856	940	6,655	18.6%	948	8
PJM East	W_OP	$ 65	5,554	17.9%	811	2.6%	31,029	883	5,613	18.1%	889	6
PJM East	SH_SP	$110	7,716	20.5%	823	2.2%	37,578	975	7,821	20.8%	986	11
PJM East	SH_P	$ 80	5,908	17.6%	813	2.4%	33,513	880	6,003	17.9%	889	9
PJM East	SH_OP	$ 55	5,522	19.1%	803	2.8%	28,924	867	5,608	19.4%	877	10

ERCOT Market - Economic Capacity

			Pre-Merger						Post-Merger (Pre-Mitigation)			
			Exelon		NRG							
Market	Period	Price	MW	Mkt Share	MW	Mkt Share	Market Size	HHI	MW	Mkt Share	HHI	HHI Chg
ERCOT	S_SP1	$250	2,995	3.8%	12,502	15.9%	78,427	847	12,502	15.9%	847	—
ERCOT	S_SP2	$130	2,995	3.8%	12,502	16.0%	78,404	847	12,502	16.0%	847	—
ERCOT	S_P	$ 75	2,750	3.7%	11,720	15.9%	73,801	865	11,720	15.9%	865	—
ERCOT	S_OP	$ 65	1,118	1.9%	9,231	15.5%	59,386	790	9,231	15.5%	790	—
ERCOT	W_SP	$ 90	2,964	3.8%	11,932	15.5%	77,085	822	11,932	15.5%	822	—
ERCOT	W_P	$ 60	1,114	2.2%	5,285	10.2%	51,724	700	5,285	10.2%	700	—
ERCOT	W_OP	$ 55	1,114	2.2%	5,285	10.3%	51,367	696	5,285	10.3%	696	—
ERCOT	SH_SP	$100	2,803	4.0%	10,858	15.3%	70,873	807	10,858	15.3%	807	—
ERCOT	SH_P	$ 70	1,505	2.4%	9,600	15.2%	63,171	827	9,600	15.2%	827	—
ERCOT	SH_OP	$ 50	1,072	2.6%	4,208	10.1%	41,734	758	4,208	10.1%	758	—

North Zone Market -Economic Capacity

			Pre-Merger						Post-Merger (Pre-Mitigation)			
			Exelon		NRG							
Market	Period	Price	MW	Mkt Share	MW	Mkt Share	Market Size	HHI	MW	Mkt Share	HHI	HHI Chg
North Zone	S_SP1	$250	2,878	8.4%	3,123	9.1%	34,370	1,762	3,123	9.1%	1,762	—
North Zone	S_SP2	$130	2,878	8.4%	3,123	9.1%	34,347	1,760	3,123	9.1%	1,760	—
North Zone	S_P	$ 75	2,750	8.3%	3,162	9.6%	32,971	1,757	3,162	9.6%	1,757	—
North Zone	S_OP	$ 65	1,118	4.2%	2,941	11.0%	26,837	1,495	2,941	11.0%	1,495	—
North Zone	W_SP	$ 90	2,842	8.4%	2,932	8.7%	33,705	1,660	2,932	8.7%	1,660	—
North Zone	W_P	$ 60	1,114	4.4%	2,243	8.9%	25,104	1,236	2,243	8.9%	1,236	—
North Zone	W_OP	$ 55	1,114	4.4%	2,244	8.9%	25,104	1,229	2,244	8.9%	1,229	—
North Zone	SH_SP	$100	2,697	8.6%	2,790	8.9%	31,382	1,618	2,790	8.9%	1,618	—
North Zone	SH_P	$ 70	1,505	5.4%	2,775	9.9%	28,087	1,635	2,775	9.9%	1,635	—
North Zone	SH_OP	$ 50	1,072	4.7%	2,151	9.4%	22,945	1,236	2,151	9.4%	1,236	—

Houston Zone Market - Economic Capacity

			Pre-Merger						Post-Merger (Pre-Mitigation)			
			Exelon		NRG							
Market	Period	Price	MW	Mkt Share	MW	Mkt Share	Market Size	HHI	MW	Mkt Share	HHI	HHI Chg
Houston Zone	S_SP1	$250	483	1.8%	10,193	38.9%	26,202	1,875	10,193	38.9%	1,875	—
Houston Zone	S_SP2	$130	483	1.8%	10,193	38.9%	26,202	1,875	10,193	38.9%	1,875	—
Houston Zone	S_P	$ 75	349	1.5%	9,426	39.4%	23,932	1,977	9,426	39.4%	1,977	—
Houston Zone	S_OP	$ 65	184	0.9%	7,034	33.1%	21,262	1,639	7,034	33.1%	1,639	—
Houston Zone	W_SP	$ 90	519	1.9%	9,905	35.8%	27,711	1,667	9,905	35.8%	1,667	—
Houston Zone	W_P	$ 60	217	1.1%	3,429	17.9%	19,200	1,138	3,429	17.9%	1,138	—
Houston Zone	W_OP	$ 55	217	1.1%	3,431	17.9%	19,200	1,140	3,431	17.9%	1,140	—
Houston Zone	SH_SP	$100	504	2.0%	9,012	36.0%	25,037	1,668	9,012	36.0%	1,668	—
Houston Zone	SH_P	$ 70	243	1.1%	7,792	35.0%	22,249	1,696	7,792	35.0%	1,696	—
Houston Zone	SH_OP	$ 50	228	1.6%	2,541	18.2%	13,993	1,193	2,541	18.2%	1,193	—

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Exhibit J-9

Exelon-NRG Merger: Available Economic Capacity DPT Results in PJM

PJM - Available Economic Capacity

			Pre-Merger						Post-Merger (Pre-Mitigation)			
			Exelon		NRG							
Market	Period	Price	MW	Mkt Share	MW	Mkt Share	Market Size	HHI	MW	Mkt Share	HHI	HHI Chg
PJM	S_SP1	$250	4,832	9.8%	701	1.4%	49,331	544	5,533	11.2%	572	28
PJM	S_SP2	$160	5,369	10.1%	735	1.4%	53,420	527	6,105	11.4%	555	28
PJM	S_P	$ 90	5,194	8.0%	585	0.9%	65,251	547	5,779	8.9%	561	14
PJM	S_OP	$ 50	1,961	3.8%	269	0.5%	51,756	875	2,230	4.3%	879	4
PJM	W_SP	$105	5,153	8.8%	580	1.0%	58,632	479	5,732	9.8%	497	17
PJM	W_P	$ 75	3,728	6.8%	581	1.1%	54,588	491	4,309	7.9%	505	15
PJM	W_OP	$ 50	1,899	4.3%	255	0.6%	44,390	602	2,154	4.9%	607	5
PJM	SH_SP	$100	4,380	9.8%	488	1.1%	44,519	559	4,868	10.9%	580	22
PJM	SH_P	$ 70	2,126	5.2%	522	1.3%	41,092	609	2,648	6.5%	622	13
PJM	SH_OP	$ 45	1,612	4.8%	203	0.6%	33,694	882	1,815	5.4%	887	6

PJM East - Available Economic Capacity

			Pre-Merger						Post-Merger (Pre-Mitigation)			
			Exelon		NRG							
Market	Period	Price	MW	Mkt Share	MW	Mkt Share	Market Size	HHI	MW	Mkt Share	HHI	HHI Chg
PJM East	S_SP1	$250	2,555	13.9%	438	2.4%	18,429	576	2,993	16.2%	642	66
PJM East	S_SP2	$200	3,596	17.6%	398	1.9%	20,457	657	3,994	19.5%	725	68
PJM East	S_P	$100	1,403	7.4%	198	1.0%	18,978	500	1,601	8.4%	516	15
PJM East	S_OP	$ 60	374	2.2%	59	0.3%	17,220	535	433	2.5%	537	1
PJM East	W_SP	$120	2,536	13.9%	194	1.1%	18,230	598	2,730	15.0%	627	30
PJM East	W_P	$ 90	1,271	7.1%	171	1.0%	17,925	481	1,442	8.0%	495	14
PJM East	W_OP	$ 65	364	2.3%	65	0.4%	15,890	455	430	2.7%	456	2
PJM East	SH_SP	$110	2,600	15.0%	245	1.4%	17,391	593	2,845	16.4%	635	42
PJM East	SH_P	$ 80	1,120	6.5%	147	0.9%	17,343	465	1,267	7.3%	476	11
PJM East	SH_OP	$ 55	396	2.5%	75	0.5%	15,716	513	471	3.0%	515	2

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Exhibit J-10

Exelon-NRG Merger: DPT Results in ERCOT

ERCOT Market - Economic Capacity

			Pre-Merger						Post-Merger (Pre-Mitigation)			
			Exelon		NRG							
Market	**Period**	**Price**	**MW**	**Mkt Share**	**MW**	**Mkt Share**	**Market Size**	**HHI**	**MW**	**Mkt Share**	**HHI**	**HHI Chg**
ERCOT	S_SP1	$250	2,995	3.8%	12,502	15.9%	78,427	847	15,497	19.8%	969	122
ERCOT	S_SP2	$130	2,995	3.8%	12,502	16.0%	78,404	847	15,497	19.8%	969	122
ERCOT	S_P	$ 75	2,750	3.7%	11,720	15.9%	73,801	865	14,470	19.6%	983	118
ERCOT	S_OP	$ 65	1,118	1.9%	9,231	15.5%	59,386	790	10,349	17.4%	848	59
ERCOT	W_SP	$ 90	2,964	3.8%	11,932	15.5%	77,085	822	14,896	19.3%	941	119
ERCOT	W_P	$ 60	1,114	2.2%	5,285	10.2%	51,724	700	6,399	12.4%	744	44
ERCOT	W_OP	$ 55	1,114	2.2%	5,285	10.3%	51,367	696	6,399	12.5%	741	45
ERCOT	SH_SP	$100	2,803	4.0%	10,858	15.3%	70,873	807	13,661	19.3%	928	121
ERCOT	SH_P	$ 70	1,505	2.4%	9,600	15.2%	63,171	827	11,105	17.6%	900	72
ERCOT	SH_OP	$ 50	1,072	2.6%	4,208	10.1%	41,734	758	5,279	12.7%	809	52

North Zone Market - Economic Capacity

			Pre-Merger						Post-Merger (Pre-Mitigation)			
			Exelon		NRG							
Market	**Period**	**Price**	**MW**	**Mkt Share**	**MW**	**Mkt Share**	**Market Size**	**HHI**	**MW**	**Mkt Share**	**HHI**	**HHI Chg**
North Zone	S_SP1	$250	2,878	8.4%	3,123	9.1%	34,370	1,762	6,001	17.5%	1,914	152
North Zone	S_SP2	$130	2,878	8.4%	3,123	9.1%	34,347	1,760	6,001	17.5%	1,912	152
North Zone	S_P	$ 75	2,750	8.3%	3,162	9.6%	32,971	1,757	5,912	17.9%	1,916	160
North Zone	S_OP	$ 65	1,118	4.2%	2,941	11.0%	26,837	1,495	4,059	15.1%	1,586	91
North Zone	W_SP	$ 90	2,842	8.4%	2,932	8.7%	33,705	1,660	5,774	17.1%	1,807	147
North Zone	W_P	$ 60	1,114	4.4%	2,243	8.9%	25,104	1,236	3,357	13.4%	1,315	79
North Zone	W_OP	$ 55	1,114	4.4%	2,244	8.9%	25,104	1,229	3,358	13.4%	1,308	79
North Zone	SH_SP	$100	2,697	8.6%	2,790	8.9%	31,382	1,618	5,487	17.5%	1,771	153
North Zone	SH_P	$ 70	1,505	5.4%	2,775	9.9%	28,087	1,635	4,280	15.2%	1,741	106
North Zone	SH_OP	$ 50	1,072	4.7%	2,151	9.4%	22,945	1,236	3,222	14.0%	1,324	88

Houston Zone Market - Economic Capacity

			Pre-Merger						Post-Merger (Pre-Mitigation)			
			Exelon		NRG							
Market	**Period**	**Price**	**MW**	**Mkt Share**	**MW**	**Mkt Share**	**Market Size**	**HHI**	**MW**	**Mkt Share**	**HHI**	**HHI Chg**
Houston Zone	S_SP1	$250	483	1.8%	10,193	38.9%	26,202	1,875	10,676	40.8%	2,018	143
Houston Zone	S_SP2	$130	483	1.8%	10,193	38.9%	26,202	1,875	10,676	40.8%	2,018	143
Houston Zone	S_P	$ 75	349	1.5%	9,426	39.4%	23,932	1,977	9,776	40.9%	2,092	115
Houston Zone	S_OP	$ 65	184	0.9%	7,034	33.1%	21,262	1,639	7,217	33.9%	1,696	57
Houston Zone	W_SP	$ 90	519	1.9%	9,905	35.8%	27,711	1,667	10,424	37.6%	1,801	134
Houston Zone	W_P	$ 60	217	1.1%	3,429	17.9%	19,200	1,138	3,646	19.0%	1,178	40
Houston Zone	W_OP	$ 55	217	1.1%	3,431	17.9%	19,200	1,140	3,649	19.0%	1,180	40
Houston Zone	SH_SP	$100	504	2.0%	9,012	36.0%	25,037	1,668	9,516	38.0%	1,813	145
Houston Zone	SH_P	$ 70	243	1.1%	7,792	35.0%	22,249	1,696	8,035	36.1%	1,773	76
Houston Zone	SH_OP	$ 50	228	1.6%	2,541	18.2%	13,993	1,193	2,769	19.8%	1,252	59

Note: Imports into ERCOT market includes 820 MW from the SPP DC tie and 286 MW from the CFE DC tie.

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Exhibit J-11

Exelon-NRG Merger: DPT Results in CSWS

CSWS Market - Economic Capacity

			Pre-Merger						Post-Merger (Pre-Mitigation)			
			Exelon		NRG							
Market	Period	Price	MW	Mkt Share	MW	Mkt Share	Market Size	HHI	MW	Mkt Share	HHI	HHI Chg
CSWS	S_SP1	$250	521	3.8%	15	0.1%	13,557	4,517	536	4.0%	4,517	1
CSWS	S_SP2	$130	521	3.9%	15	0.1%	13,528	4,517	536	4.0%	4,518	1
CSWS	S_P	$ 80	521	4.0%	15	0.1%	13,153	4,410	536	4.1%	4,411	1
CSWS	S_OP	$ 50	522	5.9%	20	0.2%	8,848	2,930	542	6.1%	2,933	3
CSWS	W_SP	$ 90	514	3.8%	24	0.2%	13,392	4,053	539	4.0%	4,054	1
CSWS	W_P	$ 65	516	4.3%	24	0.2%	12,018	3,707	541	4.5%	3,709	2
CSWS	W_OP	$ 40	2	0.0%	43	1.0%	4,357	5,484	45	1.0%	5,484	—
CSWS	SH_SP	$ 90	484	3.9%	28	0.2%	12,497	3,976	513	4.1%	3,978	2
CSWS	SH_P	$ 70	487	4.1%	32	0.3%	11,886	3,860	519	4.4%	3,862	2
CSWS	SH_OP	$ 40	2	0.1%	57	1.4%	4,221	4,891	59	1.4%	4,891	—

CSWS Market - Available Economic Capacity

			Pre-Merger						Post-Merger (Pre-Mitigation)			
			Exelon		NRG							
Market	Period	Price	MW	Mkt Share	MW	Mkt Share	Market Size	HHI	MW	Mkt Share	HHI	HHI Chg
CSWS	S_SP1	$250	540	12.9%	17	0.4%	4,186	2,869	556	13.3%	2,879	10
CSWS	S_SP2	$130	536	12.8%	16	0.4%	4,186	2,862	552	13.2%	2,871	10
CSWS	S_P	$ 80	535	9.1%	15	0.3%	5,889	2,275	549	9.3%	2,279	5
CSWS	S_OP	$ 50	533	12.8%	48	1.2%	4,153	2,809	582	14.0%	2,839	30
CSWS	W_SP	$ 90	530	8.6%	22	0.4%	6,185	2,064	552	8.9%	2,070	6
CSWS	W_P	$ 65	546	8.8%	28	0.5%	6,227	2,060	574	9.2%	2,068	8
CSWS	W_OP	$ 40	14	1.7%	204	23.8%	857	892	218	25.5%	972	80
CSWS	SH_SP	$ 90	513	10.2%	40	0.8%	5,050	1,960	553	11.0%	1,976	16
CSWS	SH_P	$ 70	517	8.1%	29	0.5%	6,378	2,069	547	8.6%	2,077	7
CSWS	SH_OP	$ 40	17	1.7%	209	20.8%	1,005	795	226	22.5%	866	71

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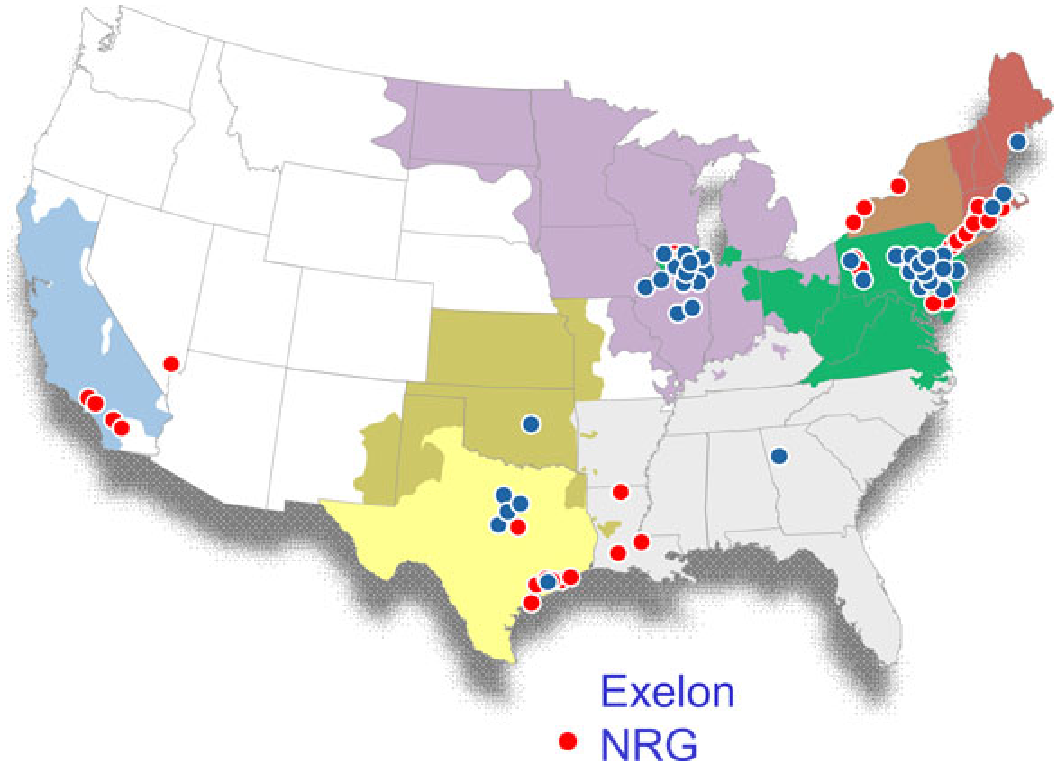
ExhibitK: Maps

A Map of the properties owned by Exelon and NRG is provided below.



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ExhibitL: Status of Regulatory Actions and Orders

Approvals from the following state and federal approvals are required for the Transaction. As of the date of this Application, no such approvals have been obtained.

State Approvals

1. Certain elements of the Transaction must be approved by Pennsylvania Public Utility Commission – the scope of the PAPUC's jurisdiction depends on the Transaction structure ultimately adopted.
2. The New York Public Service Commission
3. The California Energy Commission
4. The California Public Utilities Commission
5. The Public Utility Commission of Texas

In addition, the applicability of the newly amended Massachusetts statute to the Transaction is under review with the Massachusetts Department of Public Utilities may be required. The need for this approval has not yet been definitively determined.

Federal Approvals

1. Nuclear Regulatory Commission
2. Clearance from the Department of Justice under the Hart-Scott-Rodino Antitrust Improvements Act.
3. Approval from the Federal Communications Commission for the transfer of certain licenses.

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Exhibit M: Cross Subsidization

Cross subsidization are addressed in the attached Affidavits of Elizabeth A. Moler and Susan B. Abbott.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Exelon Corporation	)	Docket No. EC09-______

AFFIDAVIT OF SUSAN D. ABBOTT

Q. Please state your name, occupation and employer.

A. My name is Susan D. Abbott. I am a managing director with New Harbor Incorporated. New Harbor is an investment-banking firm engaged in strategic advisory services for the electric, gas and water utilities sectors.

Q. What is the purpose of your testimony?

A. Exelon Corporation (“Exelon”) has asked me to explore and explain the concept of ring-fencing, what it is, what constitutes effective ring-fencing, and whether the steps Exelon proposes to take to ring-fence Commonwealth Edison Company (“ComEd”) and PECO Energy Company (“PECO”) will effectively insulate them from the financial and business risks of the parent and its non-utility affiliates.

Q. Please summarize your conclusion.

A. I have reviewed and considered the conditions set forth in the Application, and refer the reader to the Application for a detailed understanding of each commitment. It is my opinion that Exelon has committed to take extraordinary steps to create substantial insulation between ComEd and PECO on one hand, and Exelon and its non-utility subsidiaries on the other. These new ring-fencing commitments will be put in place once the acquisition of NRG Energy, Inc. (“NRG”) is completed, and will provide effective protection for investors in, and customers of, both ComEd and PECO.

Q. What are your qualifications?

A. I have worked in the financial services sector for over 30 years. My first job was as an analyst for Aetna Life and Casualty in its Bond Investment Department where I analyzed and recommended fixed-income offerings of regulated utilities. I worked for 20 years for Moody’s Investors Service (“Moody’s”) where, as

Managing Director, I was responsible for the ratings of all public electric and combination utilities, and project finance deals. Since leaving Moody's and joining New Harbor, I have been involved in strategic advisory and rating agency advisory work, and expert witness testimony on behalf of utility clients. I have an undergraduate degree in Literature from Syracuse University, and an M.B.A. from The University of Connecticut ("UConn"). I sit on the Advisory Board of the Student Managed Fund at UConn, and am a member of the UConn Business Hall of Fame. I have lectured at UConn, the Wharton Business School, and was a faculty member of the Public Utilities Executive Course at The University of Idaho for 10 years.

Q. How do you define "ring-fencing?"

A. Ring-fencing involves the imposition of conditions and restrictions that financially separate a subsidiary from its parent company in order to protect investors in, and customers of, the subsidiary from the financial instability or potential bankruptcy of a parent company which may have a different risk profile than the subsidiary. For purposes of this discussion, I will be talking about utilities and not other types of corporations which might have the same issues, but are without the regulatory protections that already partially insulate utilities from their affiliates.

Q. Are there regulatory protections already in place sufficient to protect a utility from the business risks of the parent or its affiliates?

A. Various regulatory requirements, such as regulatory approval for utility security issuances, affiliate transactions, accounting, asset transfers, and so forth, provide significant financial insulation between utilities and their affiliates. These protections however, normally are not enough to fully insulate utilities from the business and financial risk of their parents. Shortly after the announcement of Exelon's proposed acquisition of NRG, Standard & Poor's (but not other credit rating agencies) lowered its corporate credit rating on Exelon Corp., Exelon Generation and PECO. The senior secured rating of PECO was lowered from "A" to "A-". I have no basis to know whether the downgrade of PECO was a direct result of the proposed transaction or whether it was the result of other developments such as competitive procurement issues or a change in the ability to receive competition transition charges, or a combination of these and other factors. Whatever the reason for S&P's actions, however, the new commitments being put in place by Exelon will provide significantly more protection of its utility subsidiaries from the business risks at the parent or affiliate companies, and go beyond what the rating agencies require to consider a utility effectively "ring-fenced" from its parent.

Q. What are the major benefits of "ring-fencing?"

A. Ring-fencing accomplishes four important things: it 1) helps a utility avoid credit contamination from its parent, or non-utility affiliates; 2) reduces the possibility of default on financial obligations on the part of the utility; 3) avoids having the utility added to a bankruptcy proceeding involving the parent; and 4) allows the rating agencies to insulate the ratings of the utility subsidiary from those of the parent.

Q. Has anyone delineated the actions required to achieve effective ring-fencing?

A. Yes. The rating agencies have long considered ring-fencing measures as a means of insulating utilities from the business and financial risks of their parents and non-utility affiliates, and have established various ring-fencing conditions. Rating agencies and regulators approach ring-fencing with the same objective of protecting the utility from financial stress at the parent or affiliate companies, and view the criteria for effective ring-fencing in basically the same way.

Q. Are there specific examples to look to in order to understand what makes for effective ring-fencing?

A. Yes. The Oregon Public Utilities Commission ("OPUC") addressed this issue when Enron purchased Portland General Electric. Oregon had the statutes and rules in place that enabled it to put effective ring-fencing provisions in place.

Q. What governs effective ring-fencing?

A. Rating agencies such as Moody's and S&P examine the extent to which ring-fencing provisions are enforceable, and therefore can be relied on. For example, they look to whether ring-fencing covenants are contained in loan documentation, preferably for publicly-listed securities with the longest maturities. They also examine other legal or regulatory requirements that effectively separate the business dealings of the parent and its subsidiaries. Regulatory actions such as those of the OPUC have satisfied the rating agencies as well.

Q. What are the rating agencies' conditions?

A. Each rating agency expresses its conditions in a different way. Moody's has been very specific, while S&P has been more general. However, the general theme is consistent. S&P has stated in its Corporate Rating Criteria publication that "any action that … provides support (whether legal, regulatory, financial or operational) to the utility and/or isolates the utility (most importantly financial obligations) from its parent company will be positive for credit." Moody's delineates four conditions that need to be met for ring-fencing to be considered effective. These conditions appear in a Special Comment written in May 2007 entitled Covenants and Ring-Fencing for Wholly-Owned Subsidiaries.

Q. What is the first of Moody's four conditions?

A. The first is that there is a comprehensive suite of ring-fencing covenants. Moody's is looking for clear separation of the financial dealings of the parent and unregulated affiliates from those of the regulated subsidiaries. Key to the restrictions necessary to effectively ring-fence a utility are:

- *Moody's condition*: that there be restrictions on leverage and/or distributions to the parent such that the utility's capital structure is consistent with its rating level.

  Exelon proposal: if Exelon's proposed commitments become effective, each utility subsidiary will be required to have at least one independent director, all dividends paid by the utility to the parent must be approved by an independent director, and each utility subsidiary must provide 30 days notice to its respective state regulator before paying dividends on common stock; each utility will use its reasonable best efforts and exercise prudent management as relates to dividends and capital investment in an effort to maintain investment grade ratings.

- *Moody's condition*: guarantees of debt of the parent or affiliates by the regulated subsidiary are prohibited.

  Exelon proposal: Exelon is committing to a prohibition of guarantees by its utility subsidiaries of any parent or affiliate debt, and a reciprocal prohibition on any guarantees of utility subsidiary debt by the parent or any affiliated companies.

- *Moody's condition*: all transactions with the parent and affiliates must be on an arm's length basis, and in the ordinary course of business.

  Exelon proposal: Exelon has committed to maintain corporate governance structures, controls and procedures designed to protect against affiliate abuse and foster arm's length transactions.

- *Moody's condition*: no cross-default or cross-acceleration of debt of the parent or an affiliate is allowed.

  Exelon proposal: Exelon is agreeing to no cross-defaults among the utility subsidiaries and the parent or other affiliates. In addition, Exelon is going further by agreeing that in ComEd's or PECO's debt or credit agreements there will be no rating agency triggers related to Exelon or its non-utility affiliates.

Q. What is the second Moody's condition?

A. The second condition is that the ring-fencing protections are enforceable either through covenants contained in financing documents, or through some other means. Moody's expresses the requirement that the "ring-fencing covenants [are] embedded in [the] capital structure." Normally they evaluate the "materiality" of ring-fencing commitments in terms of what proportion of debt contains the covenants. In the case of Exelon and its proposed ring-fencing of ComEd and PECO, the covenants are being made with regulators and apply to the entirety of both companies. Therefore, Exelon's proposal meets the materiality test because they are enforceable and they apply across the board to the full range of debt securities as well as to significant business dealings between the utilities and their affiliates.

Q. What is the third Moody's condition?

A. That there is no "financial and/or business dependence" reflected through inter-company loans, cash-pooling schemes or common pension funds with large liabilities of the parent that the subsidiary could inherit. This lessens the opportunity for a financially strapped parent or affiliate to absorb financial assets the regulated subsidiary has that should be used for the benefit of its customers and lenders. The ring-fencing commitments Exelon is making prohibit inter-company loans except through the money pool arrangements the companies file with FERC.

Q. What is Moody's last condition?

A. That there are no substantive consolidation provisions in the jurisdiction in which the company operates, or there is an absence of de-facto circumstances that could trigger substantive consolidation. Substantive consolidation is the situation whereby a parent drags a utility subsidiary into bankruptcy, thereby putting the utility's assets at risk to be used to satisfy obligations of the parent. Any chance that a parent could cause a simultaneous bankruptcy filing needs to be considered non-existent. When substantive consolidation provisions exist, law firms are asked to, and will if they find that the necessary protections are in place, provide opinions to the effect that in their legal judgment a bankruptcy judge would not allow the utility's assets to be consolidated with the parent's in bankruptcy. Moody's will give weight to a legal opinion on the risk of substantive consolidation depending, of course, on the content and firmness of the opinion. Exelon has committed to provide a substantive consolidation opinion for each of its utility subsidiaries prepared by well-respected law firms.

Q. Is there anything else that Moody's requires?

A. Yes. All of the above assumes appropriate disclosure for monitoring purposes. Exelon commitments include access to books, records and utility accounts consistent with applicable regulations, and transparent allocation of shared facilities and personnel.

Q. Does S&P require anything different?

A. S&P hasn't been as precise about its specific requirements for ring-fencing as has Moody's, but S&P's practice has been to require a combination of structural, legal and regulatory ring-fencing to provide enough barriers and disincentives that a holding company would be unable to take actions that would disadvantage a subsidiary.

Q. Are there particular restrictions or activities S&P cites as providing insulation?

A. Yes. In its Corporate Ratings Criteria publications S&P specifically cite restrictions of dividends, prohibitions against intercompany loans, and requirements for arms length transactions.

Q. Why did the OPUC construct ring-fencing conditions for Portland General?

A. When Enron purchased Portland General in 1996, the OPUC was concerned about the disparity between Enron's business risk profile and appetite, and Portland General's more conservative, service oriented mandate. OPUC determined that it was in the best interest of Portland General, its customers and lenders, to require separation of the utility from its new parent in the event the parent, with its riskier business plan, found itself in financial distress. The OPUC stated that "whether via merger conditions or via statutory constructs, it is possible to limit negative influences and protect the utility and ratepayers." That's exactly what happened. Because of the ring-fencing, neither Portland General's customers nor its bondholders suffered the effects of Enron's demise, and the utility was able to maintain a 9 rating notch difference above Enron.

Q. What were the ring-fencing techniques that the OPUC used?

A. The OPUC utilized a variety of ring-fencing conditions to protect Portland General. These conditions included: prohibition of allocations or direct charges from Enron to Portland General; a requirement that any bankruptcy filing be approved by holders of $1.00 "Golden Share" junior preferred; prohibition on PGE making distributions to shareholders that would cause PGE's common equity to fall below 48% of the total PGE capital without regulatory approval; creation of independent directorship; maintenance of separate debt and preferred securities; notification of dividends and distributions to Enron; restrictions on Enron's access to Portland General's assets; review of intercompany transactions; and prohibition on Portland General seeking a higher cost of capital than it would be authorized to absent the merger.

Q. What is Exelon proposing?

A. Exelon is suggesting a number of items described in its Application, including separate Boards of Directors with at least one independent director on the boards of its utility subsidiaries; whose vote is required before a utility may file for bankruptcy or pay dividends; maintenance of separate debt and separate credit ratings; no cross-guarantees; neither ComEd nor PECO will lend money to Exelon or any non-utility affiliate except pursuant to money pool arrangements filed with the FERC; arm's length business transactions; notification to regulators of utility dividend payments; and restrictions on the parent's access to the utilities' assets. In addition, ComEd and PECO will each deliver a non-consolidation opinion to each of their respective state regulators and FERC.

Q. How do these proposals compare to the ring-fencing conditions imposed by rating agencies and the OPUC?

A. Exelon's proposals compare favorably to what both rating agencies have stipulated is required to achieve effective ring fencing. The following chart lays out the rating agencies' requirements against Exelon's proposals. The chart also includes the conditions the OPUC quite successfully placed on Enron. As can be seen, Exelon's proposals compare favorably to the conditions that protected Portland General during the Enron bankruptcy, and go further than the OPUC/Enron conditions in some very important ways that provide barriers to financial transactions that could harm the utilities and their customers and lenders.

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Rating Agency Condition	Exelon Proposal	OPUC/Enron Condition
Leverage and/or dividend restrictions	Action to declare or pay dividends requires the affirmative vote of a majority of the members of the Board of Directors including the vote of at least one independent director; the Utilities must notify their respective state regulators of their intention to declare and pay dividends; each Utility will use its reasonable best efforts and exercise prudent management as relates to dividends and capital investment in an effort to maintain investment grade ratings	Notification of dividends and distributions to parent. Prohibition on PGE making distributions to shareholders that would cause PGE's common equity to fall below 48% of the total PGE capital without regulatory approval.
Prohibition of debt guarantees by utility for parent or affiliates	Prohibition of debt guarantees or granting of mortgages for the benefit of the parent or affiliates without regulatory approval	
Arm's length business transactions	Maintenance of corporate governance structure, controls and procedures designed to protect against affiliate abuse and foster arm's length business transactions	
No cross-default or cross-acceleration	No cross-defaults with or rating agency triggers related to parent or affiliates	
Ring-fencing covenants contained in financing documents	Ring-fencing covenants being made to regulators and apply across the board to a full range of debt securities as well as to significant business dealings between affiliates	
No financial interdependence as expressed through intercompany loans, cash pooling schemes or common pension funds with large liabilities	No intercompany loans except pursuant to "money pool" arrangements filed with FERC	Review of intercompany transactions
No substantive consolidation	Non-consolidation opinion will be provided	

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Rating Agency Condition	Exelon Proposal	OPUC/Enron Condition
	Additional Commitments	
	Separate Boards of Directors with at least one independent director on each Utility board	Independent directorship created
	Each utility will issue its own long-term debt	Maintain separate debt and preferred stock
	Utility Cost of capital will not reflect any risk adjustment associated with Exelon	Utility not allowed to seek higher cost of capital than it would otherwise be authorized absent the merger
	ComEd and PECO will maintain their own books	Maintain separate accounting systems
	ComEd and PECO will not transfer assets to any other Exelon affiliate without requisite regulatory approval	Restrictions on parent’s access to utility’s assets
	Bankruptcy is subject to a majority vote of the Board of Directors, including the vote of at least one independent director	Bankruptcy is subject to vote of $1.00 “Golden Share” Junior Preferred
	The utilities will be managed by their Boards of Directors in accordance with their status as public utilities. Transparent controls and procedures for cost allocations.	Allocations or direct charges from parent to utility prohibited without Commission permission
	Audit records of Exelon and non-utility affiliates that are relevant to the costs incurred by the regulated utilities	Audit records of parent and unregulated subs that are basis for charges to utility
	Power purchases unless undertaken pursuant to an auction or competitive bidding is subject to a majority vote of the Board of Directors, including the vote of at least one independent director	

Q. Are you satisfied that Exelon’s proposals provide effective ring-fencing?

A. I believe that Exelon has satisfied the conditions that the rating agencies employ, and provided an even stronger foundation for protection of the utilities from parent or affiliate financial difficulties than the OPUC provided for Portland General Electric. Since Portland General survived, without loss, Enron’s spectacular bankruptcy, I am comfortable that Exelon’s proposed provisions will ring-fence ComEd and PECO quite effectively.

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Q. Does that conclude your testimony?

A. Yes it does.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Exelon Corporation	)	Docket No. EC09-______

Affidavit of Elizabeth A. Moler on Behalf of Exelon Corporation

1. My name is Elizabeth A. Moler. I am the Executive Vice President, Government and Environmental Affairs at Exelon Corporation. I am providing this affidavit in connection with the Application of Exelon Corporation ("Exelon") pursuant to section 203 of the Federal Power Act ("FPA") for the approval of a transaction ("Transaction") regarding Exelon's acquisition of voting securities of and control over NRG Energy, Inc. and its public utility subsidiaries.

2. Under the amendments to FPA section 203 implemented by EPAct, the Commission "shall approve" the proposed transaction "if it finds that the proposed transaction . . . will not result in cross-subsidization of a non-utility associate company or the pledge or encumbrance of utility assets for the benefit of an associate company, unless . . . the cross-subsidization, pledge, or encumbrance will be consistent with the public interest."

3. In Order Nos. 669, 669-A and 669-B, the Commission identified a four-factor test that applicants must satisfy in order to address the concerns identified in section 203 regarding any possible cross-subsidization, pledge or encumbrance of utility assets associated with the proposed transaction. Under this test, the Commission examines whether a proposed transaction results, at the time of the transaction or in the future, in:

(1) transfers of facilities between a traditional utility associate company with wholesale or retail customers served under cost-based regulation and an associate company;

(2) new issuances of securities by traditional utility associate companies with wholesale or retail customers served under cost-based regulation for the benefit of an associate company;

(3) new pledges or encumbrances of assets of a traditional utility associate company with wholesale or retail customers served under cost-based regulation for the benefit of an associate company;

(4) new affiliate contracts between non-utility associate companies and traditional utility associate companies with wholesale or retail customers served under cost-based regulation, other than non-power goods and services agreements subject to review under FPA sections 205 and 206.

4. The purpose of this affidavit is to address each of these factors as they apply to the Transaction. My affidavit is based on the description of the Transaction and the commitments set forth in the Application, on my personal knowledge of the Transaction, and on the facts and circumstances that are reasonably foreseeable as of the date of this affidavit:

A. Transfers of Facilities

The Transaction does not call for any transfers of any facilities of the traditional utility associate companies, Commonwealth Edison Company ("ComEd"), PECO Energy Company ("PECO") (collectively, the "Regulated Companies"), either at the time of the Transaction or in the future.

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B. **New Issuance of Securities**

No new securities will be issued by the Regulated Companies in connection with the Transaction at the time of the Transaction, and no issuances associated with the Transaction are contemplated in the future.

C. **New Pledge or Encumbrance**

The Regulated Companies will not enter into any new pledges or encumbrances in connection with the Transaction at the time of the Transaction, and there are no plans to do so in the future.

D. **New Affiliate Contracts**

No new contracts between either Regulated Company and any affiliates are contemplated by the Transaction, either at the time of the Transaction or in the future.

5. Based on the above, it is clear that the Transaction satisfies the Commission's four-part test.

6. Further, affiant sayeth not.

Washington, District of Columbia

Elizabeth A. Moler hereby states that the statements contained in the foregoing testimony are true and correct to the best of his knowledge and belief.

____

Elizabeth A. Moler

SUBSCRIBED AND SWORN TO BEFORE ME, this ___ day of December, 2008

UNITED STATES OF AMERICA

BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Exelon Corporation	**)**	**Docket No. EC09-______**

NOTICE OF FILING
(___, 2008)

Take notice that on December 18, 2008, Exelon Corporation and its subsidiaries that are public utilities subject to the Commission's jurisdiction (collectively, "Exelon") filed an application pursuant to Section 203 of the Federal Power Act and Part 33 of the Commission's regulations requesting that the Commission approve a transaction (the "Transaction") that includes: (1) Exelon's acquisition of voting securities of NRG Energy, Inc. ("NRG Energy"); (2) Exelon's acquisition of control over NRG Energy and its subsidiaries that are public utilities subject to the Commission's jurisdiction (collectively, "NRG"); and (3) the subsequent restructuring and consolidation of Exelon and NRG to establish a more efficient corporate structure for the combined company. Exelon requests that the Commission grant its approval no later than May 1, 2009.

Any person desiring to be heard or to protest said filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, DC 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.211 and 18 C.F.R. § 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make the protestants parties to the proceedings. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection.

Magalie R. Salas
Secretary

Comment Date: [ ]