

138 FERC 61,167
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Philip D. Moeller, John R. Norris,
and Cheryl A. LaFleur.

Exelon Corporation
Constellation Energy Group, Inc.

Docket Nos. EC11-83-000
EC11-83-001

ORDER CONDITIONALLY AUTHORIZING MERGER
AND DISPOSITION OF JURISDICTIONAL FACILITIES

(Issued March 9, 2012)

1. On May 20, 2011, as amended on October 11, 2011, Exelon Corporation (Exelon) and Constellation Energy Group, Inc. (Constellation) and their respective public utility subsidiaries (collectively, Applicants) filed a joint application pursuant to sections 203(a)(1) and 203(a)(2) of the Federal Power Act (FPA)¹ requesting authorization for a merger and disposition of jurisdictional facilities by which Exelon will acquire and combine with Constellation (Proposed Transaction).
2. The Commission has reviewed the application under the Commission's Merger Policy Statement.² As discussed below, we conditionally authorize the Proposed Transaction as consistent with the public interest.

¹ 16 U.S.C. § 824b (2006).

² *Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement*, Order No. 592, FERC Stats. & Regs. ¶ 31,044 (1996), *reconsideration denied*, Order No. 592-A, 79 FERC ¶ 61,321 (1997) (Merger Policy Statement). *See also FPA Section 203 Supplemental Policy Statement*, FERC Stats. & Regs. ¶ 31,253 (2007) (Supplemental Policy Statement). *See also Revised Filing Requirements Under Part 33 of the Commission's Regulations*, Order No. 642, FERC Stats. & Regs. ¶ 31,111 (2000), *order on reh'g*, Order No. 642-A, 94 FERC ¶ 61,289 (2001). *See also Transactions Subject to FPA Section 203*, Order No. 669, FERC Stats. & Regs. ¶ 31,200 (2005), *order on reh'g*, Order No. 669-A, FERC Stats. & Regs. ¶ 31,214, *order on reh'g*, Order No. 669-B, FERC Stats. & Regs. ¶ 31,225 (2006).

I. Background**A. Description of the Parties****1. Exelon**

3. Exelon is a public utility holding company that distributes electricity to approximately 5.4 million customers in Illinois and Pennsylvania, and natural gas to 480,000 customers in the Philadelphia area. Exelon states that its operations include energy generation, power marketing, and energy delivery, through Exelon's principal subsidiaries as described below.

a. Commonwealth Edison Company

4. Commonwealth Edison Company (ComEd) is engaged in the purchase, transmission, distribution and sale of electricity to residential, commercial, industrial and wholesale customers in northern Illinois. ComEd delivers electricity to retail customers in its service territory that either the customers purchase from retail energy suppliers, or that ComEd, as the default supplier, purchases for them from wholesale energy suppliers. ComEd's transmission system consists of approximately 5,000 miles of transmission lines. ComEd does not own any generation, but instead obtains all of its energy requirements for retail customers from market sources pursuant to the Illinois Commerce Commission's approved procurement process.

b. PECO Energy Company

5. PECO Energy Company (PECO) is engaged 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 Philadelphia. Pennsylvania permits competition by alternative generation suppliers for retail generation supply. Transmission and distribution service remain fully regulated. PECO is required to provide generation services and provider of last resort services to customers who do not choose an alternative supplier. PECO does not own any generation, but satisfies its provider of last resort obligations by purchasing power. PECO must satisfy its provider of last resort obligations through a competitive-procurement process approved by the Pennsylvania Public Utility Commission (Pennsylvania Commission).

6. ComEd and PECO have both placed their transmission systems under the operational control of PJM Interconnection, L.L.C. (PJM). Under the PJM open access transmission tariff (OATT), 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.

7. Exelon's regulated gas services business is conducted solely by PECO and the gas service rates are regulated by the Pennsylvania Commission.

c. Exelon Ventures Company LLC

8. Exelon Ventures Company LLC (Exelon Ventures) is a holding company through which Exelon owns 100 percent of the membership interests in Exelon Generation Company, LLC (Exelon Generation). Exelon Generation is the generation business for Exelon, and has its own generation assets and wholesale power marketing unit. Exelon Generation owns, or controls through long-term contracts, generation assets throughout the country. The wholesale power marketing unit ensures delivery to its customers through long-term and short-term contracts, including PECO's load requirements and contracts for a portion of ComEd's load requirements, and markets any remaining energy in the wholesale bilateral and spot markets.

2. Constellation

9. Constellation is an integrated energy holding company that has both a regulated utility and competitive energy operations, including merchant generation plants and competitive and wholesale and retail businesses with separate market-based rate authorizations. Constellation owns Baltimore Gas & Electric (BGE), an electric transmission and distribution company and natural gas distribution company in Maryland. Constellation's competitive energy supply business provides energy in competitive wholesale and retail power markets. Constellation owns, or controls through long-term contracts, approximately 16,600 MW of electric generating facilities in the Northeast, Mid-Atlantic, Southeast, Western, and Texas regions. Other Constellation subsidiaries provide competitive retail natural gas services and products to improve energy efficiency for residential and commercial customers.

10. Constellation offers approximately 1,600 MW of demand response in markets across North America including: New England (ISO-New England Inc. (ISO-NE)); New York (New York Independent System Operator, Inc. (NYISO)); the Mid-Atlantic States (PJM); Texas (Electric Reliability Council of Texas, Inc. (ERCOT)); and California. Applicants state that with the merger, the combined company will be better positioned to continue its investment in its demand response business.

a. BGE

11. BGE, an indirect, wholly-owned subsidiary of Constellation, transmits and distributes electricity to approximately 1.2 million customers and provides retail natural gas service to approximately 630,000 customers in all or part of 10 counties in central Maryland and the City of Baltimore, Maryland. BGE has no captive retail customers because the State of Maryland has adopted retail choice. BGE is obligated to provide market-based standard offer service to all of its electric customers who elect not to select

a competitive energy supplier. BGE owns approximately 1,300 circuit miles of FERC-jurisdictional transmission facilities, 240 substations and approximately 24,800 circuit miles of distribution lines. BGE has transferred operational control of its transmission facilities to PJM. PJM provides open-access transmission service over those facilities under the terms of the PJM Tariff.

b. Constellation Power Source Generation, Inc.

12. Constellation Power Source Generation, Inc. (CPSG) owns and or operates: (i) over 3,600 MW of generating capacity at nine wholly-owned generation facilities in Maryland; (ii) 539.8 MW in generating capacity associated with partial ownership interests in Keystone and Conemaugh generating plants in Pennsylvania; and (iii) an entitlement to 277 MW in generating capacity from a hydroelectric generating plant in Pennsylvania by virtue of a stock interest in Safe Harbor Water Power Corporation. All of CPSG's generating facilities are located in the PJM balancing authority area. CPSG has been granted market-based rate authority by the Commission.³

c. Other Constellation Subsidiaries

13. Constellation Energy Nuclear Group, LLC (CENG) serves as a holding company for Constellation's interests in nuclear generation and provides corporate and engineering services for these facilities. In 2009, EDF, Inc. (EDF) purchased a 49.99 percent interest in CENG leaving Constellation with a 50.01 percent interest.⁴

14. Constellation Energy Commodities Group, Inc. (CCG) is an indirect, wholly-owned subsidiary of Constellation authorized by the Commission to sell energy, capacity, and certain ancillary services at market-based rates.⁵ CCG focuses on serving the full requirements power needs of distribution utilities, cooperatives, and municipalities that competitively source their load requirements. CCG also sells natural gas and other commodities at wholesale.

15. Constellation NewEnergy, Inc. (CNE), a wholly-owned subsidiary of Constellation, is a competitive retail energy provider that provides energy services to commercial, industrial and residential customers throughout the United States and

³ See *Constellation Power Source Generation, Inc.*, Docket No. ER00-2918-000 *et al.* (Jul. 24, 2009) (unpublished delegated letter order).

⁴ *EDF Development Inc.*, 126 FERC ¶ 61,141 (2009).

⁵ See *Constellation Energy Commodities Group, Inc.*, Docket No. ER05-261-000 (Jan. 6, 2005) (unpublished delegated letter order).

Canada. The Commission granted CNE market-based rate authority;⁶ however, CNE does not own any generation, transmission, or distribution assets.

16. Additionally, Constellation owns a variety of energy-related businesses, including retail gas supply, electric generation, electric products and services, fuel processing, and operations and maintenance services.

B. Description of the Proposed Transaction

17. As set forth by the terms and conditions of the Agreement and Plan of Merger, dated as of April 28, 2011, by and among Exelon, Bolt Acquisition Corporation (Merger Sub),⁷ and Constellation, Merger Sub will merge with and into Constellation. Constellation will continue as the surviving entity and become a wholly-owned subsidiary of Exelon.⁸ Applicants state that, upon completion of the merger, Constellation shareholders will receive 0.93 shares of Exelon common stock for every share of Constellation common stock that they own. Applicants estimate that, immediately following completion of the Proposed Transaction, Exelon shareholders will own approximately 78 percent of the combined company while Constellation shareholders will own approximately 22 percent of the combined company.

II. Notice of Filing and Responsive Pleadings

18. Notice of the application was published in the *Federal Register*, 76 Fed. Reg. 30,934 (2011), with interventions and comments due on or before July 19, 2011. Notices of intervention were filed by the Pennsylvania Commission and the Maryland Public Service Commission (Maryland Commission). Timely motions to intervene were filed by Monitoring Analytics, LLC (PJM Market Monitor), RG Steel LLC, EDF, American Municipal Power Inc., Dominion Resources Services, Inc., Pennsylvania Office of the Consumer Advocate (PA Consumer Advocate), Nucor Steel Kankakee, Inc., the PPL

⁶ See *Baltimore Gas & Elec. Co.*, Docket No. ER99-2948-008, *et al.* (Feb. 7, 2007) (unpublished delegated letter order).

⁷ Merger Sub is a wholly-owned subsidiary of Exelon.

⁸ Immediately after closing, Constellation will transfer its entire equity interest in RF Holdco LLC, an intermediate holding company that owns BGE, to Exelon which will immediately transfer that interest to Exelon Energy Delivery Company, LLC. Then, Exelon will transfer its equity interest in Constellation to Exelon Ventures which will immediately transfer its interest in Constellation to Exelon Generation. As a result, Constellation (exclusive of RF Holdco LLC and BGE) will become a wholly-owned subsidiary of Exelon Generation.

Companies,⁹ Tenaska Taylorville, LLC, FirstEnergy Corp. (FirstEnergy), Northeast Utilities Service Company, and the Maryland Office of the People's Counsel (MD Consumer Advocate). Out of time motions to intervene were filed by Old Dominion Electric Cooperative, NSTAR Electric Company, New Jersey Division of Rate Counsel, and Interstate Gas Supply, Inc. Illinois Municipal Energy Agency (IMEA) filed a timely motion to intervene and protest and MD Consumer Advocate and PA Consumer Advocate (together, MD/PA Consumer Advocates) filed a timely joint protest and request for evidentiary hearing. The PJM Market Monitor, the People of the State of Illinois (Illinois AG) and American Public Power Association (APPA) filed out-of-time protests. On August 3, 2011, Applicants filed an answer to the comments and protests. On September 1, 2011, the PJM Market Monitor filed a status report informing the Commission of a possible anomaly in the results of its analysis of the competitive effects of the Proposed Transaction, and filed a further report updating its analysis on September 16, 2011. On September 2, 2011, the Commission issued a notice of proposed communication between Commission advisory staff and staff from the U.S. Department of Justice. On September 20, 2011, the Illinois AG filed a request for leave to respond to Applicants' answer, and Applicants filed a reply to the Illinois AG on September 28, 2011.

19. On October 11, 2011, both Applicants and the PJM Market Monitor made filings informing the Commission that Applicants had reached an agreement with the PJM Market Monitor addressing the PJM Market Monitor's concerns, with Applicants amending their filing by proposing additional mitigation measures. Notice of Applicants' filing was published in the *Federal Register*, 76 Fed. Reg. 66,054 (2011), with interventions and comments due on or before November 1, 2011.¹⁰ A notice of intervention and protest was filed by the Virginia State Corporation Commission (Virginia Commission). Timely comments or protests were filed by MD/PA Consumer Advocates, American Antitrust Institute (AAI), and Calpine Corporation (Calpine), and the Illinois AG. On November 3, 2011, Applicants filed an answer to the protests and comments. On November 14, 2011, Applicants filed a letter with the Commission

⁹ The PPL Companies include: PPL Montana, LLC; Kentucky Utilities Company; PPL Electric Utilities Corporation; LG&E Energy Marketing Inc.; Louisville Gas & Electric Company; PPL Colstrip I, LLC; PPL Colstrip II, LLC; Lower Mount Bethel Energy, LLC; PPL Martins Creek, LLC; PPL Brunner Island, LLC; PPL Montour, LLC; PPL Susquehanna, LLC; PPL New Jersey Solar, LLC; PPL Renewable Energy, LLC; PPL Holtwood, LLC; PPL New Jersey Biogas, LLC; and PPL EnergyPlus, LLC.

¹⁰ The Commission considers a settlement agreement filed prior to a dispositive order as an amendment to the application. *BHE Holdings Inc.*, 133 FERC ¶ 61,231, at n.7 (2010).

requesting that the Commission act on the application prior to January 5, 2012. On November 22, 2011, the Illinois AG filed a renewed request for a hearing, which Applicants answered on November 28, 2011.¹¹

III. Discussion

A. Procedural Issues

20. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2011), the notices of intervention and timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding. Pursuant to Rule 214(d) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214(d) (2011), the Commission will grant the late-filed motions to intervene given the parties' interest in the proceeding, the early stage of the proceeding, and the absence of undue prejudice or delay.

21. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2011), prohibits an answer to a protest or an answer unless otherwise ordered by the decisional authority. We will accept the Illinois AG's and Applicants' answers because they have provided information that assisted us in our decision-making process.

B. Analysis Under Section 203

22. Section 203(a)(4) requires the Commission to approve a transaction if it determines that the transaction will be consistent with the public interest.¹² The Commission's analysis of whether a transaction will be consistent with the public interest generally involves consideration of three factors: (1) the effect on competition; (2) the effect on rates; and (3) the effect on regulation.¹³ Section 203(a)(4) also requires the Commission to find that the 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 Commission determines that the cross-subsidization, pledge, or encumbrance will be consistent with the public interest." The Commission's

¹¹ On February 27, 2012, Stuart LeVene filed an out-of-time protest regarding outages at his property served by BGE. The Commission notes that under the FPA, retail matters are not within the Commission's jurisdiction. Further, Mr. LeVene's criticisms are unrelated to the Proposed Transaction.

¹² 16 U.S.C. § 824b(a)(4) (2006).

¹³ See Merger Policy Statement, FERC Stats. & Regs. ¶ 31,044 at 30,111.

regulations establish verification and informational requirements for applicants that seek a determination that a transaction will not result in inappropriate cross-subsidization or pledge or encumbrance of utility assets.¹⁴

1. Effect on Competition

a. Horizontal Market Power

23. Applicants provide information on the effect on horizontal market power of the Proposed Transaction. We first address the relevant geographic markets to be considered, then the analysis of horizontal market power within these markets, and finally address the proposed mitigation measures provided in the application and in the subsequent amendment.

i. Relevant Markets

(a) Applicants' Analysis

24. Applicants state that, with the proposed mitigation measures described below, the Proposed Transaction will not raise any horizontal market power concerns.¹⁵ They identify the relevant products across the relevant geographic markets as energy, capacity and ancillary services.

25. In their analysis, Applicants state that Exelon and Constellation own or control overlapping generation in three relevant geographic markets: PJM, ISO-New England Inc. (ISO-NE), and the Electric Reliability Council of Texas, Inc. (ERCOT). Applicants state that the extent of the overlap is *de minimis* in two of these markets, namely, ISO-NE and ERCOT.¹⁶ Specifically, in ISO-NE, Applicants state that Constellation owns or controls 3,273 MW of generation capacity, which, when combined with Exelon's 185 MW of capacity, increases market share by about 0.5 percent or an increase in Herfindahl-Hirschman Index (HHI) of 9 points.¹⁷ In ERCOT, Applicants state that

¹⁴ 18 C.F.R. § 33.2(j) (2011).

¹⁵ Application at 18.

¹⁶ *Id.* at 19.

¹⁷ The HHI is a widely accepted measure of market concentration, calculated by squaring the market share of each firm competing in the market and summing the results. The HHI increases both as the number of firms in the market decreases and as the disparity in size between those firms increases. Markets in which the HHI is less than 1,000 points are considered to be unconcentrated; markets in which the HHI is greater than or equal to 1,000 but less than 1,800 points are considered to be moderately

(continued...)

Exelon owns or controls 3,774 MW of generation capacity, which, when combined with Constellation's 1,242 MW, increases market share by 1.7 percent or an HHI change of approximately 17 points.

26. In PJM, Applicants state that Exelon owns or controls 22,247 MW of generation capacity and Constellation owns or controls 7,966 MW of generation capacity. Applicants state that, within PJM, prices can diverge due to internal transmission constraints and thus, in analyzing market power issues, they considered smaller submarkets within PJM, as well as PJM as a whole.¹⁸ Applicants analyzed these markets and concluded that there is only a *de minimis* overlap of 40 MW of generation resources in the PJM East submarket. Notwithstanding, based on transmission congestion data, Applicants also analyze two potential new submarkets within PJM - AP South¹⁹ and the 5004/5005 submarket²⁰ - in order, according to Applicants, to eliminate any doubt as to whether the Proposed Transaction would result in market power in PJM. Applicants state that the AP South transmission interface was frequently constrained within PJM, binding for day-ahead transactions in 53 percent of the hours and for real-time transactions in 17 percent of the hours in 2010.²¹ Applicants determined that, in 2010, the 5004/5005 interface transmission constraint was binding for day-ahead transactions in 19 percent of

concentrated; and markets in which the HHI is greater than or equal to 1,800 points are considered to be highly concentrated. In a horizontal merger, an increase of more than 50 HHI points in a highly concentrated market or an increase of 100 HHI points in a moderately concentrated market fails its screen and warrants further review. Merger Policy Statement, FERC Stats. & Regs. ¶ 31,044 at 30,129; *see Order Reaffirming Commission Policy and Terminating Proceeding*, 138 FERC ¶ 61,109 (2012) (affirming the Commission's use of the thresholds adopted in the Merger Policy Statement).

¹⁸ Application at 21.

¹⁹ The AP South submarket, as defined by the constrained AP South interface, consists of the following 500 kilovolt (kV) lines: Mt. Storm-Doubs, Greenland Gap-Meadowbrook, Mt. Storm-Valley, and Mt. Storm-Meadowbrook. The AP South submarket consists of the following transmission zones: Atlantic City Electric Company, BGE, Dominion Resources, Delmarva Power & Light, Jersey Central Power & Light, Metropolitan Edison, PECO, Potomac Electric Company, PPL Electric, Public Service Electric & Gas, and Rockland Electric Company.

²⁰ The 5004/5005 constraint is defined by the Keystone-Juniata 5004 line and the Conemaugh Juniata 5005 line. The 5004/5005 submarket largely overlaps the AP South submarket but does not include the Dominion Transmission Zone.

²¹ Application, Exh. J-1 at 5-6.

the hours and for real-time transactions in six percent of the hours.²² The competitive screen results for the Proposed Transaction in PJM and various PJM submarkets are discussed below.

(b) Comments and Protests

27. In its comments, the PJM Market Monitor submitted an analysis of the Proposed Transaction, which includes analyses of the competitive effects of the merger on the real-time energy market with and without mitigation. The PJM Market Monitor states that it performed its analysis on the basis of every actual relevant market interval defined by an identified constraint and the PJM system software. It defines the relevant markets as those energy markets created by repeated constraints which separate the PJM system, and created local markets for supply and constraint relief, for 100 or more hours over the 2010 calendar year. The PJM Market Monitor states that its analysis falls within the Commission's regulatory guidelines, with the exception that it considers "relevant product" as that product priced at less than or equal to 50 percent of the market clearing price using cost-based offers, which, according to the PJM Market Monitor, is less restrictive than the Commission's five percent above the pre-transaction market clearing price.²³ The PJM Market Monitor notes that the 50 percent test has been approved by the Commission for use in the three pivotal supplier market power tests applied in the PJM markets.²⁴

28. The Illinois AG protests the Proposed Transaction because Applicants did not conduct any analysis of the Northern Illinois market.²⁵ The Illinois AG calculates the concentration of the suppliers in the Northern Illinois market by considering purchases by ComEd in 2010, rather than by calculating all potential suppliers, as Applicants have done. Illinois AG also attributes all of ComEd's purchases in the PJM market to a single supplier, PJM Interconnection, LLC. Therefore, the Illinois AG concludes that, using the purchase data of ComEd, the market has few major suppliers and a high HHI which could indicate the potential for competitive harm. The Illinois AG requests an evidentiary hearing to investigate the impact of the merger on Illinois ratepayers.²⁶

²² *Id.* at 7.

²³ *See* 18 C.F.R. § 33.3(c)(4).

²⁴ PJM Market Monitor July 21 Comments, Att. at 9-13.

²⁵ Illinois AG uses the phrase "Northern Illinois market" to define the area of Illinois covered by PJM.

²⁶ Illinois AG July 21 Comments at 3-5.

29. Applicants respond that the Illinois AG has not provided adequate evidence regarding transmission constraints to support its claim that Northern Illinois should be analyzed as a relevant geographic submarket. Applicants state that the Commission has previously determined that since there are significant power flows between ComEd and the rest of PJM, without finding binding transmission constraints that would limit these flows there is not sufficient evidence to conclude that the ComEd zone is a separate submarket within PJM.²⁷

30. The Illinois AG responds in turn that data to determine whether Northern Illinois should be treated as a separate market was not provided by Applicants and is not publicly available. The Illinois AG states that data that would be needed to demonstrate the existence of transmission constraints into Northern Illinois are not easily available in the public domain.²⁸

(c) **Commission Determination**

31. We will examine the entire PJM market, as well as the AP South, 5004/5005, and PJM East submarkets as relevant geographic markets. While AP South and 5004/5005 have not been previously recognized by the Commission as relevant geographic submarkets, the frequency of binding constraints on the relevant interfaces that create price separation within PJM lead us to conclude that those markets should be considered separate relevant submarkets within PJM for purposes of evaluating the Proposed Transaction. Because Applicants fail the Commission's indicative HHI screens in certain PJM markets, we will consider the Proposed Transaction's effect on competition in the relevant PJM markets in conjunction with the Applicants' mitigation measures discussed below.

32. We will not consider Northern Illinois a separate relevant submarket at this time. There is no evidence in the record that there are frequently binding transmission constraints that create prices in Northern Illinois that diverge from prices in the rest of PJM. The Commission has stated that any proposal to use an alternative geographic market must include a demonstration regarding whether there are frequently binding transmission constraints during historical seasonal peaks and at other competitively significant times that prevent competing supply from reaching customers within the

²⁷ Applicants August 3 Answer at 12 (citing *Exelon Corp.* 127 FERC ¶ 61,161, at P 86 (2009); *FirstEnergy Corp.*, 133 FERC ¶ 61,222, at P 52 (2010)).

²⁸ Illinois AG September 20 Response at 4.

proposed alternative geographic market.²⁹ This demonstration could be made by providing evidence of binding transmission constraints or price separation data.³⁰

33. We decline the Illinois AG's request to order a hearing on whether Northern Illinois is a relevant geographic submarket. We note that PJM provides transparent data on energy prices, transfers, and congestion costs on its website with additional information published by the PJM Market Monitor.³¹ This data can be used to determine relevant geographic markets in the context of this proceeding. Furthermore, the analysis presented by the Illinois AG is flawed in several respects. The analysis incorrectly and without support attributes all of the energy purchased in the PJM market to two suppliers. This assumption results in an incorrect market concentration measure. Additionally, there is no attempt to separate purchases by season or load, which is relevant to determine whether there is an ability or incentive to exert market power. As in the past, since no evidence was provided that frequent binding constraints create a submarket that is relevant to the Proposed Transaction, the Commission declines to separately consider Northern Illinois as a separate submarket within PJM.³²

ii. Competition Analysis in Relevant Markets

34. Applicants performed a Competitive Analysis Screen, as required by section 33.1 of the Commission's regulations,³³ in each market where there is more than a *de minimis* overlap to determine the market shares prior to and following the closing of the Proposed Transaction. Applicants also performed an Appendix A analysis, also referred to as a delivered price test (DPT), which requires them to estimate available generating resources, and assign load obligations, if any, to potential suppliers,³⁴ specifying the transmission network that these suppliers can use to reach the relevant destination market

²⁹ See *AEP Power Marketing, Inc.*, 124 FERC ¶ 61,274, at P 24-25 (2008) (citing Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 268 (2007)). See also *Boralex Livermore Falls LP*, 122 FERC ¶ 61,033, *order on reh'g*, 123 FERC ¶ 61,279, at P 25 (2008)).

³⁰ See *First Energy Corp.*, 133 FERC ¶ 61,222 at P 52.

³¹ See PJM eDataFeed, <http://www.pjm.com/markets-and-operations/etools/edatafeed.aspx>; see also *2010 State of the Market Report for PJM*.

³² See *Exelon Corp.*, 127 FERC ¶ 61,161 at P 86.

³³ 18 C.F.R. § 33.1 (2011).

³⁴ Load obligation estimates are only used when performing available economic capacity analysis.

and the destination market price. Applicants then calculated the change in market concentrations following the merger in each of the following 10 periods: summer super-peak 1, summer super-peak 2, summer peak, summer off-peak, winter super-peak, winter peak, winter off-peak, shoulder super-peak, shoulder peak, and shoulder off-peak.

35. Applicants analyzed both economic capacity (EC) and available economic capacity (AEC) in determining HHI changes; however, Applicants explain that most of the analysis focuses on EC measures since, in PJM, most states have implemented retail competition, which makes the AEC analysis less relevant.³⁵ Applicants point out the difficulty in deriving meaningful results from AEC analysis in markets such as PJM where there is a reduced link between ownership of generation and retail load obligations.³⁶

(a) PJM Market as a Whole

36. Under the EC analysis, Applicants determined that the Proposed Transaction fails the Commission's market power screens in four of 10 periods studied in the PJM-wide market. During those four periods, the Proposed Transaction causes a rise in market concentration as measured by the HHI of more than 100 points when the overall market is considered moderately concentrated.³⁷ Applicants contend that the screen failures are inconsequential because they primarily occur during off-peak periods.

37. Under the AEC analysis, Applicants fail screens in two periods, summer off-peak and shoulder off-peak, in the PJM-wide market with HHI rising more than 100 points in a moderately-concentrated market.³⁸

(b) PJM East

38. Applicants state that PJM East should not be considered a relevant market for purposes of the Proposed Transaction for two reasons: (1) there is at most a *de minimis* overlap in PJM East because Constellation controls only 40 MW of capacity in PJM East; and (2) PJM East has been constrained far less frequently in recent years than it had been before.³⁹ Nevertheless, Applicants studied the PJM East submarket under both the EC

³⁵ AEC measures capacity available after load obligations are met.

³⁶ Application at 24 and n.37; and Exh. J-1 at 55.

³⁷ Application, Exh. J-1 at 44.

³⁸ Application, Exh. J-9 at 1.

³⁹ Application at 22.

and AEC analyses. Under the EC analysis, Applicants state that, within the PJM East submarket, Exelon's pre-merger market share ranges from 16.6 percent to 27.4 percent, and Constellation's pre-merger market share ranges from 1.7 percent to 4.9 percent. Applicants determined that, under the EC analysis, the Proposed Transaction fails the Commission's HHI screens in four of 10 seasons and load conditions. Under Applicants' AEC analysis, the Proposed Transaction fails in seven of 10 seasons and load conditions.⁴⁰

39. Applicants argue that the screen failures in PJM East are not indicative of a potential competitive problem associated with the proposed merger. Applicants state that the screen failures are due to imports into PJM East from the rest of PJM and NYISO. Applicants state that they have no ability to restrict supplies into PJM East by withholding the generation they control outside of PJM East, because the interface capability allocated to Applicants would be taken up by rivals; the PJM East interface was a binding constraint in three percent of off-peak hours in the day-ahead market and less than one-tenth of one percent of the off-peak hours in the real-time market in 2010; the types of units under the control of Applicants within PJM East that are economic during off-peak hours are generally not suitable for strategic withholding; and the off-peak screen analysis does not capture all sources of competing generation because many combined-cycle plants are operating in off-peak hours.⁴¹

(c) **AP South**

40. Under the EC analysis, Applicants state that, within the AP South submarket, Exelon's pre-merger market share ranges from 10.3 percent to 15.4 percent, and Constellation's pre-merger market share ranges from 6.3 percent to 9.2 percent. The AP South submarket is moderately concentrated post-merger and the changes in HHI range from 132-284 points, failing the Commission's screens for all time periods and load conditions studied.

41. Under the AEC analysis, Applicants fail the Commission's screens under all seasons and load conditions studied. Applicants submit that, within the AP South submarket, Exelon's pre-merger market share ranges from 14.0 percent to 24.4 percent, and Constellation's pre-merger market share ranges from 4.8 percent to 9.3 percent. The AP South submarket ranges from unconcentrated to moderately concentrated in six periods following the Proposed Transaction and the changes in HHI during the periods when the market is moderately concentrated range from 186 to 455 points.

⁴⁰ *Id.*, Exh. J-9 at 2.

⁴¹ *Id.*, Exh. J-1 at 48.

(d) **5004/5005**

42. Under the EC analysis, Applicants state that within the 5004/5005 submarket Exelon's pre-merger market share ranges from 13.9 percent to 19.9 percent, and Constellation's pre-merger market share ranges from 8.7 percent to 12.2 percent. The 5004/5005 submarket is moderately concentrated post-merger and the changes in HHI range from 250 to 488 points, failing the Commission's screens for all time periods and load conditions studied.

43. Under the AEC analysis, Applicants fail the Commission's screens under all seasons and all load conditions studied. Applicants submit that, within the 5004/5005 submarket, Exelon's pre-merger market share ranges from 14.5 percent to 24.4 percent, and Constellation's pre-merger market share ranges from 5.4 percent to 10.7 percent. The 5004/5005 submarket ranges from moderately concentrated in certain periods to highly concentrated in the summer off-peak period following the Proposed Transaction. Specifically, the changes in HHI during the periods when the market is moderately concentrated range from 157 to 560 points.⁴²

(e) **Other Product Markets**

44. In the capacity markets, Applicants studied the effect of the Proposed Transaction on the PJM-wide Reliability Pricing Model (RPM) market. Applicants looked at the percentage of resources that Exelon and Constellation would control relative to all of the resources that were eligible to participate in the 2014/2015 Base Residual Auction. Applicants found that the change in HHI as a result of the Proposed Transaction would be 87 points in an unconcentrated market.⁴³

45. Applicants also studied the impact of the Proposed Transaction on capacity markets in Locational Deliverability Area (LDA) submarkets within PJM. Applicants examined the Mid-Atlantic Area Council (MAAC) and Eastern Mid-Atlantic Area Council (EMAAC) LDAs. In the MAAC LDA, the Proposed Transaction will cause a screen failure and create a moderately concentrated market with an HHI increase of 238 points. In the EMAAC LDA, the Proposed Transaction will result in an increase of 133 points in a moderately concentrated market.⁴⁴

⁴² Application, Exh. J-9 at 2.

⁴³ Application, Exh. J-1 at 59.

⁴⁴ *Id.* at 61.

46. Applicants also examined the impact of the Proposed Transaction on the PJM Ancillary Services market, including the following products: energy imbalance, regulation, synchronized reserve and supplemental reserves. Applicants state that, with one exception, the PJM ancillary services markets are essentially RTO-wide markets and, absent a finding of a substantial amount of Applicants' generation being unusually well suited to provide ancillary services, or a finding that Applicants supply a disproportionately large share of ancillary services, one should not expect the proposed merger to raise competitive concerns in these markets.⁴⁵ Applicants further state that energy imbalance services are provided through the real-time energy market.⁴⁶ Applicants state that the Proposed Transaction raises no competitive concerns in the regulation market.⁴⁷ Applicants state that Exelon and Constellation each account for small shares of regulation supplies clearing in the regulation market. They state that in the PJM regulation market, the change in HHI attributable to the Proposed Transaction is 31 points.⁴⁸ Applicants also state that the total regulation supply offered is approximately three times the average requirements.⁴⁹

47. Applicants state that, in the Synchronized Reserve Market, resources are either categorized as Tier 1 or Tier 2 synchronized reserves. Tier 1 resources are paid when they respond to an identified spinning event based on a specific calculation which includes a premium to locational marginal price (LMP). The price for Tier 2 synchronized reserves is determined in the Synchronized Reserve Market. Applicants state that they are small participants in the Synchronized Reserve Market for Tier 2 synchronized reserves, and the Proposed Transaction raises no competitive concerns in these markets.

48. Applicants also analyzed the impact of the Proposed Transaction on the Day-Ahead scheduling reserve market, an RTO-wide market. Applicants state that the combined market share of the Applicants as a result of the Proposed Transaction raises the HHI by 12 points.

⁴⁵ *Id.* at 63.

⁴⁶ *Id.* at 64.

⁴⁷ *Id.* The regulation market is the market for regulation service, an ancillary service that balances short-term changes in supply and demand to maintain the frequency of the transmission system.

⁴⁸ *Id.*

⁴⁹ *Id.* (citing *2010 State of the Market Report for PJM*, Vol. 2, at 421).

(f) **Commission Determination**

49. Based on the evidence and record in this proceeding, we find that the Proposed Transaction raises horizontal market power concerns in the relevant submarkets within PJM as well as PJM as a whole. These concerns, as noted by Applicants, reflect screen failures in certain PJM energy and capacity markets that must be addressed in order to mitigate any existence of market power post-merger. Accordingly, we will review the effect on horizontal market power in light of Applicants' proposed mitigation to address the screen failures observed in the relevant PJM markets, as described below.

iii. **Proposed Mitigation**

(a) **Mitigation Proposal in Application**

50. Applicants provided a mitigation proposal in their application, which was later supplemented by additional commitments as a result of an agreement reached with the PJM Market Monitor. We discuss both below beginning with the commitments made in the application.

51. In their application, Applicants propose mitigation to cure the screen failures in the PJM energy market as well as in the AP South and 5004/5005 energy submarkets. Applicants' mitigation proposal also addresses competitive harm in the PJM capacity market. Applicants propose, as mitigation for the screen failures in the energy markets, the divestiture of three generation plants in Maryland with 2,648 MW of baseload and intermediate capacity: Brandon Shores, a coal-fired facility with 1,286 MW of nameplate capacity; H.A. Wagner, a facility with 459 MW of coal-fired capacity and 504 MW of gas/oil-fired units on the same site; and C.P. Crane, a facility with 385 MW coal-fired nameplate capacity and 14 MW of gas/oil fired units on the same site. Applicants agree to enter into a contract for divestiture of those facilities within 180 days of the closing of the merger.⁵⁰ Applicants assert that the proposed plant divestitures, when combined with a reduction of approximately 600 MW of PJM capacity attributed to Constellation beginning January 1, 2015, will be "more than sufficient to eliminate all screen failures."⁵¹

⁵⁰ All of the generation capacity is in 5004/5005, the smallest submarket studied. Because 5004/5005 is within the AP South market and AP South is within PJM, divesting capacity within 5004/5005 also addresses screen failures in the wider market.

⁵¹ Application at 26. Applicants explain that the reduction of approximately 600 MW of PJM capacity attributed to Constellation results from the termination of Constellation's contractual right to market EDF's share of the output of CENG's nuclear plants at the end of 2014.

52. Additionally, Applicants commit to enter into fixed price power sales contracts to sell 500 MW per hour of around-the-clock baseload energy (24 hours per day/7 days a week) until December 31, 2014 for delivery into the 5004/5005 submarket.⁵² Applicants state that these contracts will have a term of one year or longer and will be entered into within 180 days after the closing of the merger. This commitment to sell 500 MW of firm energy with liquidated damages for failure to deliver will be made at a fixed price established at the time of the contract.

53. Applicants also propose to address unresolved screen failures in the PJM capacity markets. Specifically, following the Proposed Transaction and the implementation of the mitigation described above, Applicants will continue to fail the Commission's screens in the EMAAC LDA. Applicants attribute this screen failure to a tolling agreement for the Delta plant that gives Constellation control over 545 MW of capacity, and which expires on May 31, 2017.⁵³ Applicants propose to implement an offer cap that will commence on the consummation of the Proposed Transaction. Starting at that time, Applicants will offer all of their not-previously-committed generation capacity in the EMAAC submarket not subject to reliability-must-run (RMR) agreements in all PJM capacity auctions covering periods between the consummation of the Proposed Transaction and the earlier of May 31, 2017 or the date the Delta tolling agreement is terminated or divested, either at a zero price or below the offer cap approved by PJM or the PJM Market Monitor for each resource. Applicants will bid the Delta plant at a zero price in all such auctions, unless the Delta tolling agreement is sold or terminated effective before any such auctions take place.⁵⁴

54. Applicants propose additional interim mitigation measures to ensure that no market power issues are raised in the AP South submarket. The interim mitigation will apply to sales of energy, capacity, and ancillary services from the Mitigated Units,⁵⁵ and

⁵² Applicants August 3 Answer at 5. Applicants state that this sale is not tied to a specific unit.

⁵³ A tolling agreement effectively transfers control over a specified facility by granting the buyer the right to the facility's output at its discretion. Constellation's tolling agreement for the Delta plant (since renamed the York Energy Center) expires May 31, 2017, after which Applicants will not have the ability to control that capacity.

⁵⁴ Application at 27.

⁵⁵ The Mitigated Units are, with limited exceptions, all of those fossil-fired and hydroelectric units that Applicants own or control that are located in the AP South submarket, which includes PJM East and 5004/5005. The Mitigated Units include: Chester 7-9; Croydon 11, 12, 22, 31, 32, 41, 42; Delaware 9-12; Eddystone 3-4; Eddystone 10-40; Fairless Hills A, B; Falls 1-3; Montenay; Moser 1-3; Pennsbury 1, 2;

(continued...)

will be effective from the time that the Proposed Transaction is consummated until the date that the last Constellation unit to be divested is transferred to a new owner (Interim Mitigation Period).

55. During the Interim Mitigation Period, all Mitigated Units will be subject to cost-based caps on the offers that are made for the Mitigated Units into the PJM Energy market. These caps are “up to” offer caps, meaning that Applicants will be permitted to submit offers lower than the offer caps, or to “must run” a Mitigated Unit with an offer price of zero for all or a portion of the unit’s capability. The cost-based caps will equal the “Cost-Based Offer,” which is defined as an offer to sell energy at the maximum price allowed under the PJM “Amended and Restated Operating Agreement of PJM Interconnection LLC” Schedule 1, Section 6.4.2(a) ii and iii. This limits offers to the variable cost of a Mitigated Unit plus an adder, where variable cost is defined and recorded in PJM’s Cost Development Task Force rules, PJM Manual 15, and where the adder is dependent on whether or not PJM has classified the unit as a frequently mitigated unit.⁵⁶

56. Applicants state that in the PJM capacity market, during the Interim Mitigation Period, Applicants will offer into the RPM Base Residual Auctions and Incremental Auctions all of the capacity of their units in the MAAC LDA at prices not to exceed their PJM approved Market Seller Offer Caps (as defined in section 6 of the PJM Tariff), except to the extent that capacity from such units is committed pursuant to prior Base Residual Auctions or Incremental Auctions or has been sold bilaterally to third parties.⁵⁷

57. Applicants also commit that, to the extent that they offer ancillary services into the PJM ancillary services markets during the Interim Mitigation Period, for any unit, Applicants’ offers will be consistent with the rules set out in PJM’s Manual 15 – Cost

Richmond 91, 92; Schuylkill 1; Schuylkill 10, 11; Southwark 3-6; Brandon Shores; C.P. Crane; H.A. Wagner; Notch Cliff; Perryman; Philadelphia Road; Riverside; Westport; Gould Street; and Delta. The following units are excluded from the Mitigated Units: Delaware and Schuylkill diesel-fired peakers that are not offered into PJM markets; Grays Ferry cogeneration unit that Exelon does not have the right to shut down or reduce output; Eddystone 1-2, which are under RMR contracts; Muddy Run and Conowingo, which are committed as must-run units with a zero offer price; Panther Creek, which is bid into the market by FirstEnergy; and Safe Harbor, which is self-scheduled.

⁵⁶ A frequently mitigated unit as defined in PJM Manual 35 is a unit that was offer-capped for more than a defined threshold of its real-time run hours in the most recent 12-month period.

⁵⁷ Application at 44.

Development Guidelines regarding cost-based bidding. Specifically with respect to regulation service, Applicants commit to cap any offer to sell regulation service from Mitigated Units at a price no greater than a cost-based offer as determined in accordance with Section 9 of the Cost Development Guidelines.⁵⁸ With respect to synchronized reserves, Applicants commit to cap offers to sell synchronized reserves from Mitigated Units at a price up to the value calculated in accordance with Section 7 of the Cost Development Guidelines.

58. In the PJM energy market, Applicants state that, after mitigation, the Proposed Transaction passes the HHI screens in all periods. Using EC analysis, Applicants state that, after mitigation, the market is slightly above the 1,000 HHI threshold for a moderately concentrated market in three off-peak periods,⁵⁹ and remains unconcentrated in all other periods. The largest HHI increase in a moderately concentrated period is 35 points. Therefore, Applicants conclude, post-mitigation, no competitive concerns arise in the PJM market.⁶⁰ Additionally, Applicants performed a sensitivity analysis by raising the price of energy five and ten dollars per MWh. The resulting sensitivity analysis shows the PJM market, during off-peak periods, is unconcentrated and the HHI changes by no more than 43 points due to the Proposed Transaction.⁶¹

59. In the AP South submarket, Applicants state that, prior to the divestiture, there are significant screen violations. Applicants state that the screen violations are eliminated by the proposed mitigation package. Using EC analysis, Applicants state that, after mitigation, the market is slightly above the 1,000 HHI threshold for a moderately concentrated market in three off-peak periods,⁶² and remains unconcentrated in all other periods. The largest HHI increase in a moderately concentrated period is 52 points.⁶³ Applicants performed a sensitivity analysis, by raising the price of energy five and ten dollars per MWh. The sensitivity analysis shows the Proposed Transaction results in

⁵⁸ *Id.* at 44-45.

⁵⁹ *Id.*, Exh. J-7 at 5, Applicants calculate a maximum HHI for the PJM market of 1,037 during the summer off-peak period.

⁶⁰ *Id.* at 28.

⁶¹ *Id.*, Exh. J-8.

⁶² *Id.*, Exh. J-7 at 5, Applicants calculate a maximum HHI for the AP South submarket of 1,031 during the summer off-peak period.

⁶³ *Id.* at 31.

HHI changes of no more than 51 points in a moderately concentrated market during off-peak periods.⁶⁴

60. In the 5004/5005 submarket, Applicants state that, prior to the divestiture, there are significant screen violations. Applicants state that the screen violations are eliminated by the proposed mitigation package, that is by the divestitures and the behavioral commitments. Using EC analysis, Applicants state that, after mitigation, the market is slightly above the 1,000 HHI threshold for a moderately concentrated market in nine of 10 periods,⁶⁵ and remains unconcentrated in the other period. The largest HHI increase in a moderately concentrated period is 86 points.⁶⁶ Applicants performed a sensitivity analysis, by raising the price of energy five dollars per MWh. The sensitivity analysis shows the Proposed Transaction results in HHI changes of no more than 85 points during off-peak periods in a moderately concentrated market.⁶⁷

61. In the PJM East submarket, Applicants state that, prior to the divestiture, there are four screen violations. Applicants explain that the screen violations are almost entirely a result of imports into PJM East that are allocated to Applicants. Using EC analysis, three screen violations in off-peak periods persist following Applicants proposed mitigation. Applicants state that capacity outside of PJM East that is owned or controlled by Constellation or Exelon cannot be physically or economically withheld from the PJM East submarket because competitive economic generation from the rest of PJM not owned or controlled by Applicants is sufficient to supply all possible imports into PJM East.⁶⁸ Applicants performed a sensitivity analysis by raising the price of energy five dollars per MWh. The sensitivity analysis shows the Proposed Transaction results in HHI changes by no more than 76 points in the moderately concentrated PJM East submarket during off-peak periods.⁶⁹

62. Applicants assert that, because PJM operates an LMP energy market, if Applicants attempted to exert market power by raising offers or withholding generation outside of PJM East, competitive economic generation in the west would be more than sufficient to

⁶⁴ *Id.*, Exh. J-8.

⁶⁵ *Id.*, Exh. J-7 at 6, Applicants calculate a maximum HHI for the 5004/5005 submarket of 1,291 during the summer off-peak period.

⁶⁶ *Id.*

⁶⁷ *Id.*, Exh. J-8.

⁶⁸ *Id.* at 29.

⁶⁹ *Id.*, Exh. J-8.

supply all feasible imports into PJM East, thus defeating the attempt to exercise market power. Applicants conclude, therefore, that generation outside of PJM East cannot be part of a withholding strategy.⁷⁰ Applicants argue that the screen failures indicate a “false positive” and are of no competitive significance.⁷¹

**(b) Comments and Protests on Mitigation
Proposal in Application**

63. MD/PA Consumer Advocates state that the analysis of the market power impacts presented by the Applicants failed to analyze the ability of the combined company to influence market prices based on the specific plants it will own, the position of those plants in the market, and the rules governing the markets. MD/PA Consumer Advocates argue that such an analysis is especially important here, given the fact that the merger would increase market concentrations well beyond the thresholds in the Merger Policy Statement. MD/PA Consumer Advocates also argue that the Commission should not approve the Proposed Transaction unless and until it is demonstrated that the proposed divestitures will actually prevent the merged company from exercising market power in all of their markets.⁷²

64. With respect to the PJM energy market, MD/PA Consumer Advocates argue that the proposed fixed-price sale of a block of 500 MW of energy to mitigate screen failures is an “insufficient and inappropriate” form of market power mitigation.⁷³ They argue that the block sale does not alter the control over the bidding of any energy output in the market, and therefore, does not reduce the ability of any participant to exercise market power.

65. MD/PA Consumer Advocates also state that Applicants’ proposed mitigation is based on the assumption that the units to be divested will be sold to one or more new market entrants. They note that, if the divestitures were made to certain entities that already own capacity in PJM, it would not mitigate the market power issues, but would instead transfer the increase in market power from Applicants to another party. MD/PA Consumer Advocates argue that the Commission should not accept the proposed

⁷⁰ *Id.*, Exh. J-1 at fn. 20.

⁷¹ *Id.*, Exh. J-1 at 12.

⁷² MD/PA Consumer Advocates July 19 Comments at 7-8.

⁷³ *Id.* at 9.

mitigation without an additional condition, such as a restriction on the sale to a buyer with less than two percent market share in PJM.⁷⁴

66. With respect to the capacity markets, MD/PA Consumer Advocates note that the Applicants find screen failures in the EMAAC region, even with mitigation. They argue, therefore, that Applicants' proposed mitigation does not assure compliance with the Commission's merger guidelines. Additionally, MD/PA Consumer Advocates state that the expiration of the Delta tolling agreement in 2017 should not be counted as a mitigation measure, since it will not occur for six more years. The proposed interim mitigation, MD/PA Consumer Advocates argue, should also not count as mitigation, as it does nothing to affect the changes in HHI. MD/PA Consumer Advocates also argue that Applicants understate the concentration in the EMAAC capacity market, as the State of the Market Report from the PJM Market Monitor found an HHI for EMAAC in 2012/13 of 2,057, as opposed to the 1,123 figure used by Applicants.⁷⁵

67. On the arguments Applicants use to suggest that the Commission ignore the remaining screen violations, MD/PA Consumer Advocates argue that an ability in the past to develop new generation is no guarantee of a future ability. Additionally, they argue that mitigation measures already in place in PJM should not be presumed to be as effective as creating a structurally competitive market. MD/PA Consumer Advocates argue that the Commission should require additional proceedings to address the question of whether the merged company has the ability and incentive to withhold generation from the market in order to drive up market prices.

68. In addition to limiting the buyer of the divested facilities to those having no more than a two percent market share in PJM prior to the purchase, MD/PA Consumer Advocates propose further mitigation for Applicants, to include divestiture of an additional 637 MW of capacity owned by Exelon in the 5004/5005 market and the EMAAC capacity market. This capacity includes the plants at Croydon Generating Station, Fairless Hills, Richmond Generating Station, and Schuylkill Generating Station. They also propose a requirement that the buyer of these facilities have no more than a two percent market share in PJM prior to the purchase.

69. The PJM Market Monitor argues that the Proposed Transaction raises competitive issues, but that those issues could be addressed by an effective mitigation plan. However, the PJM Market Monitor indicates that the proposed divestitures would only reduce, but not eliminate, the competitive issues in the merger. In this regard, the PJM Market Monitor makes an argument similar to that of the MD/PA Consumer Advocates, namely,

⁷⁴ *Id.*

⁷⁵ *Id.* at 10.

that, if the divested plants were sold to a significant player in the markets, the divestiture would exacerbate competitive concerns. It also argues that the Commission must place appropriate conditions on approval of the merger, which could include restrictions on the parties to whom assets may be divested, approving related divestitures jointly in its final decision in this proceeding, or requiring divestiture to the point where there is no structural effect on competition under an appropriate defined analytical standard.⁷⁶

70. APPA states that the Commission should evaluate carefully whether the proposed mitigation is in fact sufficient to mitigate the market power concerns. First, APPA states that certain elements of the PJM RPM are very sensitive to even small changes in the amount of generation capacity supplied. APPA notes that the Commission rejected an attempt by the Public Power Association of New Jersey to have the self-supply generation of “small utilities” exempted from the new self-supply rules of the Minimum Offer Price Rule by pointing to the steep demand curve in PJM.⁷⁷ APPA argues that if the Commission will police “buyer-side” market power in such a fashion, it should do the same for seller-side generation market power.

71. APPA also argues that the Commission should inquire into how Applicants plan to operate their combined generation fleet post-merger, and whether any changes to operations could result in the exercise of market power. APPA points to a complaint filed in the Northern District of Illinois, *David W. Pennington, et al. v. Zion Solutions LLC, et al.*, Case 1:11-cv-04754, in which plaintiffs allege that Exelon intentionally dismantled the Zion nuclear plant in order to set a high market price for generation.⁷⁸ APPA states that it is not expressing a view on the merits of the suit, but that the allegations are relevant to this docket because the potential for such profit-maximizing strategies are magnified when a company holds a large generation portfolio in a centralized market such as PJM.

72. APPA rejects the Applicants’ contention that new generation entry can dissipate any market power the merged entity may have. APPA argues that the PJM RPM has “proven much better at funneling revenues to existing generators than to supporting the entry of new generators, especially in the constrained Eastern portions of the PJM footprint.” APPA submits a June 2011 report prepared by Synapse Energy Economics,

⁷⁶ PJM Market Monitor July 21 Comments at 5-6.

⁷⁷ APPA Comments at 6.

⁷⁸ *Id.*

Inc., which argues that capacity markets have provided limited benefits at extraordinary costs, and that they may actually discourage new generation.⁷⁹

(c) **Answers and Replies**

73. Applicants state that their commitment to sell 500 MW of baseload energy through December 31, 2014 mitigates the competitive effects of Constellation's contractual rights to market EDF's share of the output of CENG's Calvert Cliffs nuclear units. Applicants argue that it is inconsistent to attribute the CENG capacity to Constellation based on a contractual right, and then argue that a contract cannot also be used to attribute that same capacity away from Constellation to a third party.⁸⁰ Applicants explain that the 500 MW block sale proposed by Applicants is superior to the sale of power from a specific unit, because Applicants' proposal requires them to make energy available on an around-the-clock basis, and they cannot withhold that supply.⁸¹

74. In the PJM capacity markets, Applicants state that the MD/PA Consumer Advocates mischaracterize Applicants' proposal as relying on expiration of the Delta tolling agreement as a mitigation measure. Instead, according to Applicants, the mitigation measure consists of the bidding caps agreed to by Applicants.⁸²

75. Applicants also state that their calculations for available supply into the PJM capacity market are correct. Applicants explain that the PJM Market Monitor calculates a higher HHI for various PJM markets because the PJM Market Monitor does not take into account potential imports or demand response resources.⁸³ Therefore, the market concentration appears higher than it actually is due to the understatement of actual potential supply.

76. Applicants state that the Commission will have the opportunity to consider the competitive effects of any divestiture based on the specific facts regarding the purchaser when Applicants file an application under section 203 for the approval of the sale.⁸⁴ Applicants also argue that they are not required to submit an analysis on strategic

⁷⁹ *Id.* at 8-9.

⁸⁰ Applicants August 3 Answer at 4.

⁸¹ *Id.* at 5.

⁸² *Id.* at 7.

⁸³ *Id.* at 8.

⁸⁴ *Id.* at 9.

withholding, noting that such an analysis is not required by either the Commission's Merger Policy Statement or merger regulations.⁸⁵

77. Applicants state that the Illinois AG submitted flawed calculations because the Illinois AG's HHI calculations are based on purchases by ComEd in 2010 in MWh and exclude other potential suppliers in the market or capable of importing into the market. Applicants also point out that the HHI calculation supplied by the Illinois AG attributes purchases of energy in the PJM market to a single supplier, identified simply as "PJM Interconnection, LLC," which, Applicants note, does not own or control any generation.⁸⁶

78. In its response to Applicants' answer, the Illinois AG argues that ownership or control of capacity is not relevant to consider for the Northern Illinois energy market; rather, the relevant market in Northern Illinois is the energy market administered by the Illinois Power Agency. The Illinois AG argues that the HHI calculation that it presents is based on actual bidders into the Northern Illinois market. The Illinois AG argues that the Commission should not include suppliers who potentially may be capable of serving Northern Illinois, but have not done so, and therefore lower the HHI measure.⁸⁷

79. In their reply, Applicants argue that the Illinois AG is suggesting that they should not have to conform to Commission regulations regarding the identification of appropriate relevant geographic markets in the context of market power analysis of mergers. Applicants argue that the Illinois AG's arguments constitute a collateral attack on the Commission's requirements for preparing competition analyses, and as such should be rejected.⁸⁸

80. In its renewed request for hearing, the Illinois AG points the Commission to testimony regarding the proposed RITELine transmission line that was discussed during the Maryland Commission's hearing regarding the Proposed Transaction. The Illinois AG argues that part of the justification for the need for the RITELine project was based on relieving congestion, and that Exelon wanted to "protect" its generation prices in Northern Illinois from downward price pressures from incoming wind generation.⁸⁹ The

⁸⁵ *Id.* at 10.

⁸⁶ *Id.* at 11.

⁸⁷ Illinois AG's September 20 Response at 5.

⁸⁸ Applicants' September 28 Reply at 3.

⁸⁹ Illinois AG's November 23 Protest at 3.

Illinois AG argues that the congestion projections justifying the RITELine project is evidence of a separate market in Northern Illinois.

81. Applicants respond that the predominant flows of electricity in PJM have been from west to east, and that transmission lines in PJM have been congested in an eastward direction.⁹⁰ Applicants note that the Commission has previously declined to consider markets in PJM west of the congested market as separate markets.⁹¹ Applicants state that RITELine will relieve west-to-east congestion allowing wind imports into PJM Illinois to reach the rest of PJM.⁹² Applicants conclude that the Commission should not consider Northern Illinois a separate market.

(d) Agreement with PJM Market Monitor

82. On October 11, 2011, Applicants and the PJM Market Monitor submitted terms and conditions of an agreement (the Agreement) between the PJM Market Monitor and Applicants, which, it is stated, satisfies the PJM Market Monitor's concerns regarding the Proposed Transaction, such that, if the order issued by the Commission approving the proposed merger is conditioned upon compliance by Applicants with the terms and conditions of the Agreement, then the PJM Market Monitor will not object to the Proposed Transaction.

83. Under the Agreement, Applicants commit not to sell any of the units proposed to be divested to any of eight specifically identified entities (or any affiliates thereof), as measured in Applicants' analysis, in the PJM market, the PJM MAAC market or the PJM 5004/5005 sub-market.⁹³ Applicants also agree to abide by certain behavioral commitments for a 10-year period from the closing date of the Proposed Transaction.

84. The behavioral commitments include an agreement to calculate Market Seller Offer Caps with the most current actual data available at the time of the RPM auction and update those estimates at the time of the RPM incremental auctions. Applicants also commit to neither retire nor uprate a unit unless certain conditions are met. Applicants

⁹⁰ Applicants' November 28 Answer at 2.

⁹¹ *Id.* at 2-3 (citing *Exelon Corp.*, 112 FERC ¶ 61,011, at P 124 (2005); *Exelon Corp.*, 127 FERC ¶ 61,161, at P 86 (2009); *FirstEnergy Corp.*, 133 FERC ¶ 61,222, at P 52 (2010)).

⁹² *Id.* at 4.

⁹³ The eight entities are: American Electric Power Company; First Energy Corp.; GenOn Energy, Inc.; Edison International; Dominion Resources, Inc.; Public Service Enterprise Group Incorporated; Calpine Corp.; and PPL Corporation.

further commit to offer and set notification times of their non-nuclear units according to their physical capabilities. Additionally, for all peaking plants owned or controlled by Applicants, the maximum market-based offers will be determined in accordance with the PJM Cost Development Guidelines as set forth in PJM Manual No. 15 plus certain adders. Applicants will not offer any unit or part thereof as Max Emergency⁹⁴ for more than one week with certain limited exceptions. Applicants also agree that, for each nuclear unit for which they have authority to determine offers, those units will be offered as self scheduled/must run at economic maximum with certain limited exceptions. Applicants further commit to allow PJM to schedule Conowingo Generation.⁹⁵

85. Applicants agree to continue to offer the same units as have been historically offered in the PJM reserve markets and offer nuclear units at zero dollars in the day-ahead scheduling reserves market.

(e) **Comments and Protests on Agreement**

86. AAI argues that the Agreement is based on the PJM Market Monitor's competitive analysis, which is an alternative to that which is required under the Commission's regulations. However, AAI states that this analysis may not be adequately supported.⁹⁶ AAI states that the PJM Market Monitor's alternative competitive analysis is "no less than the basis for permanent structural remedies and behavioral remedies that will be in place for 10 years,"⁹⁷ which can be expected to have a material effect on the functioning and performance of wholesale electricity markets.

87. AAI states that, while the PJM Market Monitor's competitive analysis and recommended solutions may be legitimate, they do not necessarily align with or serve as a surrogate for the Commission's. Any remedy accepted by the Commission must be thoroughly vetted in light of the Commission's competitive analysis of the Proposed Transaction.⁹⁸

⁹⁴ The maximum net electrical power that a generator can deliver for a limited period of time without exceeding specified limits of equipment stress.

⁹⁵ Conowingo is a 572 MW run-of-the-river hydroelectric generation facility located on the Susquehanna River in Darlington, Maryland.

⁹⁶ AAI Comments at 4.

⁹⁷ *Id.* at 6.

⁹⁸ *Id.* at 7.

88. The Virginia Commission requests that the restriction under the Agreement on who may purchase any of the facilities or energy to be offered for sale not apply to vertically integrated utilities operating in Virginia.⁹⁹ The Virginia Commission argues that, unlike many other states within PJM, Virginia is a state in which vertically integrated utilities own, build, and purchase generation facilities that are dedicated to serving retail load obligations. The Virginia Commission states that analysis that fails to recognize that load obligations do exist in Virginia should not serve as the basis to exclude Virginia jurisdictional utilities with such obligations from the opportunity to bid on any generation or energy offered for sale as a condition of merger approval.¹⁰⁰

89. The Illinois AG objects to the terms of the Agreement because it does not address the Northern Illinois submarket within PJM.¹⁰¹

90. Calpine asks that the Commission clarify that accepting the terms of the Agreement applies only to Applicants and the facts specific to the Proposed Transaction. Calpine also asks that acceptance of the Agreement by the Commission does not constitute a finding that Calpine has market power in PJM or any PJM submarket.¹⁰² Calpine also asks that the Commission clarify that the Agreement does not preclude Calpine from bidding on or purchasing other assets in any future sale by Applicants.¹⁰³

91. The MD/PA Consumer Advocates object to the Agreement because the mitigation proposal does not go far enough to ensure that there are no adverse effects on the markets or to maintain the requisite level of transparency in the markets.¹⁰⁴ MD/PA Consumer Advocates state that the mitigation plan must include additional levels of physical divestiture and should not include block sales of energy or “virtual divestitures” as a mitigation measure.¹⁰⁵ MD/PA Consumer Advocates state that the Agreement will not

⁹⁹ Virginia Commission Protest at 2. We note that, while the Agreement would prohibit three integrated utilities operating in Virginia from bidding on any of the generating units to be divested, it does not place any limits on entities that may bid in energy market offers.

¹⁰⁰ *Id.* at 3.

¹⁰¹ Illinois AG’s November 1 Protest at 2.

¹⁰² Calpine Comments at 3

¹⁰³ *Id.*

¹⁰⁴ MD/PA Consumer Advocates’ November 1 Comments at 8.

¹⁰⁵ *Id.* at 9-10.

provide a sufficient remedy for market power concerns and, therefore, there is an increased reliance on the PJM Market Monitor to monitor the behavioral commitments made by Applicants. MD/PA Consumer Advocates also claim there are no penalties for non-compliance by Applicants.¹⁰⁶

92. MD/PA Consumer Advocates argue that block sales are inherently flawed as a means to mitigate market power because they are temporary in nature and because it is a significant challenge to accurately track block sales in order to ascertain whether market power has been exercised or not. Instead, the MD/PA Consumer Advocates urge the Commission to require Applicants to divest an additional 637 MW of generation, which, they assert, would still be in compliance with the Agreement.¹⁰⁷

(f) Commission Determination

93. We find the Proposed Transaction, as mitigated and conditioned, will not harm competition in the relevant geographic markets. In so doing, we rely in part upon the mitigation commitments made by Applicants in the application and October 11, 2011 amendment. These include Applicants' commitment to divest 2,648 MW of nameplate generation capacity, their commitment not to sell any of the units proposed to be divested to any of eight specifically identified entities (or any affiliates thereof), as well as Applicants' commitment to sell 500 MW of energy in the 5004/5005 submarket within PJM.¹⁰⁸ Additionally, while the divestitures and the sales of energy are pending, Applicants commit to bid energy, capacity, and ancillary service at cost-based rates. Applicants also commit to cost-based bidding restrictions in the EMAAC LDA capacity submarket. As we discuss below, we require Applicants to appoint an independent entity (e.g., market monitor) to certify that Applicants have complied with the interim mitigation conditions.

94. We condition our approval on Applicants' commitment to abide by the terms of its Agreement with the PJM Market Monitor and rely in part on the commitments therein to find that the Proposed Transaction will not adversely affect competition. We note that the Agreement, through Applicants' commitments, addresses concerns raised by the MD/PA Consumer Advocates regarding the Proposed Transaction continuing to fail the Commission's HHI screens should the units proposed to be divested be sold to a party with an existing substantial market share. The terms of the Agreement also allay

¹⁰⁶ *Id.* at 11.

¹⁰⁷ *Id.* at 12-13.

¹⁰⁸ *See supra* PP 51-57, 82-85 for a description of the Applicants' proposed mitigation.

concerns that Applicants could implement a withholding strategy by retiring units that could otherwise be economically dispatched in the market, or that Applicants could change the operating characteristics of a unit without review if such a change would create market power, because Applicants agree to submit their plans for retirement to the PJM Market Monitor.

95. AAI argues that while the PJM Market Monitor’s competitive analysis and recommended solutions may be legitimate, they do not necessarily align with or serve as a surrogate for the Commission’s analysis. We agree. We also agree with AAI that “the ultimate authority in determining whether a proposed transaction is in the public interest is the Commission.”¹⁰⁹ As such, we have reviewed the Proposed Transaction to determine whether it is consistent with Commission regulations.

96. The Commission used the data available to analyze the effect of the Proposed Transaction on horizontal market power by relevant market:

(1) PJM Market as a Whole

97. When considering the PJM Market as a whole under either the EC or AEC analysis, the Proposed Transaction does not fail the Commission’s screens under any season or load condition following the divestitures of the facilities proposed by Applicants as mitigation. Specifically, after factoring in all of the proposed mitigation, the delta HHI is below 50 in all 10 seasons in the PJM market as a whole. We conclude that in the PJM Market as a whole, the Proposed Transaction with mitigation will not have an adverse effect on competition.

	PJM Wide Market								
	Post Merger			Post Divestiture			Post Divestiture and 500 MW Sale		
	Market Share	HHI	HHI Change	Market Share	HHI	HHI Change	Market Share	HHI	HHI Change
S_SP1	15.6%	852	92	14.2%	814	54	14.0%	806	47
S_SP2	15.2%	857	88	14.0%	823	54	13.7%	815	46
S_P	15.4%	918	82	14.1%	881	45	13.8%	872	36
S_OP	18.2%	1,106	104	16.5%	1,051	48	16.1%	1,037	35
W_SP	14.7%	824	79	13.6%	792	47	13.3%	784	39
W_P	15.8%	930	80	14.5%	891	41	14.1%	881	31
W_OP	18.1%	1,076	103	16.5%	1,022	48	16.0%	1,007	34
SH_SP	15.2%	853	85	14.0%	819	52	13.7%	810	42
SH_P	17.0%	1,015	102	15.6%	969	56	15.1%	956	43

¹⁰⁹ AAI Comments at 6.

SH_OP	18.4%	1,086	105	16.7%	1,031	49	16.2%	1,015	33
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Source: Applicants' Data

(2) **PJM East**

98. After the mitigation is implemented, the Proposed Transaction will continue to fail the Commission’s screens in PJM East in off-peak hours under both the EC and the AEC measures. However, the screen failures are caused by imports from the rest of PJM, and occur in off-peak hours when PJM East is rarely constrained. We therefore agree with Applicants that they “have no ability to restrict supplies into PJM East by withholding the generation they control outside the PJM East, because interface capability ‘allocated’ to the Applicants in the Appendix A would be taken up by rivals in such an effort.”¹¹⁰ Accordingly, we find that the screen failures in PJM East are not an indication of the ability to exercise market power.

	PJM East								
	Post Merger			Post Divestiture			Post Divestiture and 500 MW Sale		
	Market Share	HHI	HHI Change	Market Share	HHI	HHI Change	Market Share	HHI	HHI Change
S_SP1	20.2%	1,193	64	19.5%	1,166	38	19.4%	1,160	32
S_SP2	18.6%	1,195	66	17.9%	1,169	40	17.7%	1,161	34
S_P	19.2%	1,100	75	18.3%	1,068	43	18.1%	1,058	36
S_OP	31.8%	1,667	265	29.8%	1,546	145	29.3%	1,514	118
W_SP	19.0%	1,238	60	18.4%	1,215	37	18.2%	1,208	33
W_P	23.0%	1,213	91	22.1%	1,175	54	21.9%	1,164	44
W_OP	33.1%	1,778	261	31.2%	1,662	145	30.7%	1,629	116
SH_SP	19.3%	1,157	62	18.6%	1,132	38	18.4%	1,124	31
SH_P	23.5%	1,445	143	22.3%	1,391	88	21.9%	1,372	73
SH_OP	32.3%	1,701	270	30.5%	1,588	156	29.9%	1,553	126

Source: Applicants' Data

(3) **AP South**

99. In the AP South submarket, under either the EC or the AEC analysis, Applicants’ analysis shows that the Proposed Transaction does not fail the Commission’s screens under any season or load condition following the divestitures of the facilities proposed by Applicants as mitigation. Applicants come close to screen failures with an HHI change between 91 and 99 during off-peak periods in a moderately concentrated market. Testing sensitivities of the Applicants’ model, the Proposed Transaction would fail screens with

¹¹⁰ *Id.*, Exh. J-1 at 48.

other assumptions made, such as 20 percent lower priced energy or divestitures to an existing market participant with any owned generation. Therefore, we also consider the effect of other proposed mitigation measures (in addition to the proposed facility divestitures) on the AP South submarket including the fixed-price sale of 500 MW of long-term around-the-clock energy and the terms of the Agreement. Considering the entire mitigation package, including physical and virtual divestitures, the behavioral commitments Applicants made in the Agreement with the PJM Market Monitor, and the fact that the Proposed Transaction as mitigated does not cause screen failures, we find the Proposed Transaction, as mitigated, will not create an adverse effect on competition in the AP South submarket. The divestitures to an entity with a small market presence eliminate concerns regarding market concentration that could create the potential to exercise market power in the AP South submarket. The behavioral commitments made by Applicants, with appropriate monitoring, ensure that any temporary market concentration issues will not lead to the exercise of market power in the AP South submarket.

	AP South								
	Post Merger			Post Divestiture			Post Divestiture and 500 MW Sale		
	Market Share	HHI	HHI Change	Market Share	HHI	HHI Change	Market Share	HHI	HHI Change
S_SP1	17.7%	1,111	147	14.8%	1,024	61	14.2%	1,007	44
S_SP2	17.0%	1,092	138	14.2%	1,012	58	13.5%	994	40
S_P	17.5%	1,107	143	14.4%	1,020	56	13.7%	999	35
S_OP	24.0%	1,252	269	19.4%	1,074	91	18.2%	1,031	49
W_SP	17.0%	1,077	138	14.3%	999	60	13.6%	980	41
W_P	19.3%	1,081	171	16.2%	979	69	15.3%	953	43
W_OP	24.6%	1,261	284	20.0%	1,077	99	18.7%	1,030	52
SH_SP	16.8%	1,066	132	14.0%	989	55	13.3%	968	34
SH_P	20.6%	1,157	204	16.9%	1,033	80	15.8%	999	45
SH_OP	24.0%	1,197	270	19.5%	1,022	96	18.2%	974	47

Source: Applicants' Data

(4) **5004/5005**

100. We consider the effect of the Proposed Transaction including the physical divestitures and other proposed mitigation measures on the 5004/5005 submarket including the fixed-price sale and the terms of the Agreement. Because the energy from the fixed-price sale must be delivered in the 5004/5005 market we find the fixed-price sale is effective in lessening the incentive to raise prices or withhold output. We also find

that the behavioral commitments,¹¹¹ when monitored, are an effective tool in limiting anti-competitive conduct. We conclude that, upon consideration of the entire mitigation package, the Proposed Transaction will not cause an adverse effect on competition in the 5004/5005 submarket. We believe the mitigation package addresses the concerns expressed by the PJM Market Monitor and the MD/PA Consumer Advocates regarding the Proposed Transaction’s effect on competition because the divestiture package focuses on the market concentration in the submarket that is most impacted by the Proposed Transaction. The mitigation measures provide for Applicants to relinquish control over a large amount of generation resources such that a new competitor may enter the market to discipline prices.

	5004/5005								
	Post Merger			Post Divestiture			Post Divestiture and 500 MW Sale		
	Market Share	HHI	HHI Change	Market Share	HHI	HHI Change	Market Share	HHI	HHI Change
S_SP1	23.9%	1,244	269	19.9%	1,085	110	19.0%	1,053	78
S_SP2	23.2%	1,217	258	19.3%	1,066	107	18.3%	1,032	73
S_P	23.6%	1,228	264	19.5%	1,066	102	18.4%	1,028	64
S_OP	32.2%	1,694	488	25.9%	1,368	162	24.3%	1,291	85
W_SP	23.2%	1,200	258	19.4%	1,053	111	18.4%	1,017	75
W_P	25.7%	1,233	304	21.4%	1,051	122	20.3%	1,004	75
W_OP	32.0%	1,658	481	25.9%	1,343	166	24.2%	1,263	86
SH_SP	23.1%	1,165	250	19.2%	1,017	102	18.2%	978	63
SH_P	26.7%	1,405	344	21.8%	1,194	133	20.4%	1,135	74
SH_OP	31.8%	1,630	476	25.7%	1,321	166	24.0%	1,235	80

Source: Applicants’ Data

101. We disagree with the contention of MD/PA Consumer Advocates that the proposed block sale of 500 MW is not an appropriate mitigation measure, but rather is “more of a marketing strategy.”¹¹² While the proposed sale is not associated with any particular unit, it is still an effective mitigation proposal. Applicants’ proposal is an agreement to sell the 500 MW of baseload energy, not just offer it for sale. Specifically, Applicants commit to enter into one or more power sales contracts that would obligate Applicants to sell 500MW of energy 24x7 on a firm, liquidated damages basis, with

¹¹¹ The behavioral commitments are summarized *supra* P 84.

¹¹² MD/PA Consumer Advocates July 19 Comments, Exh. MPC/PaOCA-1 at 13-14.

delivery anywhere in the 5004/5005 submarket.¹¹³ This will act to counter the incentive Applicants may have to raise prices, as Applicants would be effectively “short” an additional 500 MW under all seasons and load conditions in the 5004/5005 submarket. The Commission has approved mitigation proposals including similar block sales in the past.¹¹⁴ In this case, we believe the block sale is an effective remedy to potential market power issues stemming from Applicants’ market shares for several reasons. First, the 500 MW sale is a must sell long-term obligation; second, the 500 MW sale is part of a larger overall mitigation package; third, the sale is a temporary measure to lessen market concentration while an existing contract is in effect; and, the sale will be within an organized market subject to market monitoring. The 500 MW block sale mitigates the incentive Applicants have to raise prices because they must enter into an obligation to sell that power at a fixed price regardless of the prevailing price.

(5) Other Product Markets

102. We will accept Applicants’ mitigation in the PJM capacity market. Applicants’ offer cap in the MAAC LDA will prevent them from exercising market power in the EMAAC where they fail Commission screens until the Delta tolling agreement expires. While the mitigation in the capacity market will not cause the Proposed Transaction to fall below the HHI thresholds for mergers that do not require further analysis,¹¹⁵ the effect of the mitigation would prevent the exercise of market power because Applicants’ bids will be capped. We recognize that Applicants presented a lower HHI for the capacity market than the PJM Market Monitor calculated for offers cleared in the completed 2012/2013 RPM auctions. However, we find that the Applicants’ calculation is a product of the appropriate inclusion, in the context of their section 203 analysis, of

¹¹³ Applicants August 3 Answer at 3-4.

¹¹⁴ See *Ameren Corp.*, 108 FERC ¶ 61,094, at P 49 (2004), *reh’g denied* 111 FERC ¶ 61,055 (2005) (accepting as effective interim mitigation a proposal to sell capacity and energy from a specific facility to non-affiliates through a competitive bidding process until such time as applicants made a showing that competitive harm from the proposed merger was otherwise mitigated); *Ameren Servs. Co.* 101 FERC ¶ 61,202, at 41 (2002) (accepting as effective interim mitigation, among other mitigation measures, a commitment to sell to non-affiliated entities a specified amount of power and energy at a market value index until such time as transmission upgrades were completed); *cf. Duke Energy Corp.*, 137 FERC ¶ 61,210, at P 85 (2011) (rejecting a mitigation proposal consisting of an obligation to offer for sale specific quantities of energy at cost-based rates because of, among other things, restrictions and uncertainties in the proposal).

¹¹⁵ See Merger Policy Statement, FERC Stats. & Regs. ¶ 31,044 at 30,124.

demand response resources, energy efficiency, and potential import capacity in addition to the unforced capacity measure in their forward looking analysis.

103. We will also accept Applicants' proposal to adhere to the cost-based offer limits in the ancillary services market as determined by PJM Cost Development Guidelines. We note that the PJM Market Monitor has found the regulation market to be uncompetitive.¹¹⁶ However, the Proposed Transaction will not worsen this condition. Further, we will accept the interim mitigation measures to bid ancillary services at cost-based rates as proposed by Applicants in the AP South submarket. We rely in part on Applicants' pledge to bid at cost-based prices within the product markets to find that the Proposed Transaction will not adversely impact competition. Because compliance with these commitments is critical to our determination that the Proposed Transaction will not adversely affect competition, we will condition our authorization on an independent overseer to ensure compliance. Applicants must appoint an independent entity (e.g., market monitor) at their own cost to certify that Applicants have complied with the interim mitigation conditions.¹¹⁷ Further, Applicants must file the report with the Commission in this docket, prepared by the independent entity each quarter following the consummation of the Proposed Transaction, through the end of the quarter in which Applicants complete the sale of the three generating units to be divested.

104. We note that while new generation entry can be effective in limiting market power, APPA's concerns regarding the effectiveness of the PJM capacity market in encouraging new entry are beyond the scope of this proceeding.¹¹⁸

(6) Additional Sensitivity Analysis

¹¹⁶ 2010 *State of the Market Report*, Vol. 2, at 421.

¹¹⁷ The independent entity should certify compliance with the interim mitigation conditions for both the energy market and capacity and ancillary services market. *See supra* P 54. While Applicants may request the PJM Market Monitor to verify the adherence to the bidding restrictions, the cost of the service should be paid by Applicants and included as a transaction-related cost for purposes of Applicants' hold harmless commitment, which is discussed below at P 118.

¹¹⁸ *See NSTAR*, 136 FERC ¶ 61,016, at P 52 (2011) (finding that concerns over the Forward Capacity Market (FCM) auctions in ISO New England were outside of the scope of the section 203 proceeding, and better addressed in a separate proceeding); *Exelon Corp.*, 127 FERC ¶ 61,161, at P 89 (2009) (finding that general criticisms of the Commission's policies were outside the scope of the section 203 proceeding).

105. Commission Staff performed additional sensitivity analyses on Applicants' price assumptions in Applicants' EC base model, raising and lowering prices ten percent in all seasons for all relevant geographic markets. In general, higher prices have a de-concentrating impact, while lower prices increase market concentration. This price movement in this analysis has a minimal impact on the overall screen results, eliminating all but one screen failure in the PJM East submarket with increased prices. Lower prices increase the market HHIs in all PJM markets and submarkets, trigger one additional screen failure, and exacerbate to an extent, the existing screen failures in PJM East.

	PJM East								
	Post Divestiture and 500 MW Sale			10% price increase			10% price decrease		
	Market Share	HHI	HHI Change	Market Share	HHI	HHI Change	Market Share	HHI	HHI Change
S_SP1	19.4%	1,160	32	19.4%	1,161	32	19.7%	1,177	33
S_SP2	17.7%	1,161	34	17.7%	1,162	34	17.7%	1,163	34
S_P	18.1%	1,058	36	17.6%	1,051	33	19.8%	1,096	44
S_OP	29.3%	1,514	118	22.9%	1,465	82	30.2%	1,582	125
W_SP	18.2%	1,208	33	18.2%	1,208	31	18.2%	1,209	29
W_P	21.9%	1,164	44	20.8%	1,149	39	19.4%	1,151	46
W_OP	30.7%	1,629	116	29.5%	1,527	103	31.4%	1,689	122
SH_SP	18.4%	1,124	31	17.9%	1,173	30	19.0%	1,075	31
SH_P	21.9%	1,372	73	19.0%	1,117	47	29.6%	1,545	117
SH_OP	29.9%	1,553	126	23.1%	1,488	84	30.8%	1,621	132

Source: Calculated by Commission Staff Using Applicants' Data

106. While the additional screen failure triggered further scrutiny of the Proposed Transaction, ultimately the additional scrutiny did not indicate that the Proposed Transaction would harm competition in the relevant markets. As mentioned above, Applicants have 40 MW of overlapping capacity within PJM East but fail screens due to the allocation of imports from the rest of PJM and NYISO. The concentrating effect due to the lower prices in the sensitivity analysis impacts the dispatch of Applicants' baseload plants, including nuclear and coal, constituting a greater percentage of the supply in the relevant geographic market. These resources, however, are poorly suited to take advantage of a withholding strategy because they are difficult to ramp up or down. Additionally, as mentioned above, because these resources are outside of PJM East, and because the failures occur at relatively lower load conditions, attempts to withhold generation, raise prices, or prevent prices from falling further, would be met with competition from other available resources outside of PJM East. For this reason, the screen failures in the PJM East submarket do not indicate that the Proposed Transaction will have an adverse effect on competition.

(7) Other Issues

107. The Virginia Commission is concerned by the inclusion of public utilities serving load in Virginia among those entities to which Applicants may not sell units proposed to be divested. The Virginia Commission argues that this restriction should not apply to integrated utilities serving retail load in Virginia. Under the AEC analysis, using Applicants' assumptions, the Proposed Transaction will still cause concerns regarding market concentration if the divested facilities are sold to a major market participant, including certain holding companies that own public utilities that serve captive customers in Virginia. We are concerned that because the facilities to be divested and the fixed-price sale of energy are located in the 5004/5005 market, transmission constraints may not allow the energy produced in that market to reach load in Virginia. We are not convinced that an exception to the restrictions agreed to by Applicants is necessary here.

108. We will clarify that, in relying upon the commitments in the Agreement, we are not making a finding that any entity selling energy in PJM or any PJM submarket, including those entities to which the divested units may not be sold to, has market power. We also will not preclude any party from acquiring generation through any future sale of other assets by Applicants, provided the transaction satisfies the Commission's standards under section 203.

b. Vertical Market Power

i. Applicants' Analysis

109. Applicants argue that the Proposed Transaction raises no vertical market power concerns. In the natural gas transportation market, Applicants collectively control firm transportation contracts that represent about five percent of the deliverable capacity into the states within PJM and between five and six percent of the AP South and 5004/5005 submarkets. Applicants state that their combined share of the storage capacity in PJM is about four percent.¹¹⁹

110. Applicants also state that their transmission facilities are under the operational control of PJM and will continue to be under the control of PJM following the consummation of the Proposed Transaction. Applicants state that the Proposed Transaction does not increase in any respect the ability of the Applicants to use their ownership or control of transmission facilities to give themselves a competitive advantage in energy markets. Applicants further state that the proposed transaction poses no concerns with respect to barriers to entry.¹²⁰

¹¹⁹ Application at 47-48.

¹²⁰ *Id.* at 48; and Exh. J-1 at 17.

ii. Comments

111. The Illinois AG claims that the Proposed Transaction combines both the generation operations and the marketing operations of the two companies, which will eliminate a major marketer on both the wholesale and retail levels. The Illinois AG claims that this will adversely affect competition and lead to higher prices. The Illinois AG claims that following the announcement of the merger, Northern Illinois forward prices for peak hours rose.¹²¹

iii. Commission Determination

112. In mergers combining electric generation assets with inputs to generating power (such as natural gas, transmission, or fuel), competition can be harmed if a merger increases the merged firm's ability or incentive to exercise vertical market power in wholesale electricity markets. For example, by denying rival firms access to inputs or by raising their input costs, a merged firm could impede entry of new competitors or inhibit existing competitors' ability to undercut an attempted price increase in the downstream wholesale electricity market.

113. In this case, we find that the proposed combination of Exelon's and Constellation's transmission and generation assets, as well as the combination of natural gas distribution and generation assets, will not harm competition because Applicants will only control a relatively small amount of natural gas deliverable capacity and storage capacity. Additionally, Applicants' transmission facilities will continue to be under the operational control of PJM. Based on Applicants representations, we find that there are no other barriers to entry that would raise vertical market power concerns. We find that the evidence presented by the Illinois AG is anecdotal and insufficient to find that the Proposed Transaction presents vertical market power concerns.

2. Effect on Rates**a. Applicants' Analysis**

114. Applicants state that the Proposed Transaction will have no adverse affect on rates. Applicants state that they have no wholesale requirements customers, so the Proposed Transaction can have no adverse impact on rates to such customers. Applicants commit for a five year period to hold transmission customers harmless from the effect of the Proposed Transaction. For that five-year period, Applicants state that they will not seek to include transaction-related costs in their transmission revenue requirements,

¹²¹ Illinois AG July 21 Protest at 4.

except to the extent they can demonstrate that transaction-related savings are equal to or in excess of all of the transaction-related costs so included.¹²²

115. Applicants state that if they seek to recover transaction-related costs through their transmission rates, they will submit a compliance filing that details how they are satisfying the hold harmless commitment.¹²³ Applicants also state that they will comply with the Commission's directives in other proceedings involving a similar hold harmless provision.¹²⁴

b. Comments

116. IMEA argues that the proposed hold harmless commitment does not go far enough to protect customers. IMEA states that the Commission should direct Applicants to pledge that they will hold transmission customers harmless from “*any and all*” costs related to the Proposed Transaction. IMEA objects to the possibility that Applicants could seek to revise their formula rates to include transaction-related costs following the expiration of the hold harmless period. IMEA argues that the hold harmless commitment should be “hard-wired” into the formula rate now, and that there should be no sunset date on the hold harmless commitment. IMEA argues that, given the possibility that there will be no offsetting benefits from the merger to customers, Applicants should not be able to receive the windfall of recovery for the costs.

117. Applicants' respond that the Proposed Transaction will not modify the terms and conditions of any existing contracts or the obligation to perform under such contracts. Applicants also clarify that “during the five years *after* the merger is consummated, they will not seek to include merger-related costs in their transmission revenue requirements, except to the extent they can demonstrate that merger-related savings are equal to or in excess of all of the transaction costs so included.”¹²⁵

c. Commission Determination

118. We accept Applicants' commitment to hold transmission customers harmless for five years from costs related to the Proposed Transaction. We interpret Applicants' hold harmless commitment to apply to all transaction-related costs, including costs related to

¹²² Application at 50.

¹²³ *Id.*

¹²⁴ *Id.* at 50-51 (citing *FirstEnergy Corp.*, 133 FERC ¶ 61,222, at P 63 (2010); *PPL Corp.*, 133 FERC ¶ 61,083, at P 26-27 (2010)).

¹²⁵ Applicants August 3 Answer at 15.

consummating the Proposed Transaction and transition costs (both capital and operating) incurred to achieve merger synergies. Transaction-related costs do not include any acquisition premium (or acquisition adjustment), including goodwill, associated with the Proposed Transaction. The Commission has stated that it “historically has not permitted rate recovery of acquisition premiums.”¹²⁶ Any acquisition premium (or acquisition adjustment) associated with the Proposed Transaction is not permitted to be included in rates absent Commission approval in a section 205 rate filing.¹²⁷

119. We note that nothing in the application indicates that rates to customers will increase as a result of transaction-related costs created by the Proposed Transaction. The Commission will be able to monitor the Applicants’ hold harmless commitment under the books and records provision of PUHCA 2005¹²⁸ and its authority under section 301(c) of the FPA, and the commitment is fully enforceable based on the Commission’s authority under section 203 of the FPA.

120. If Applicants seek to recover transaction-related costs through their wholesale power or transmission rates within five years after the Proposed Transaction is consummated, they must submit a compliance filing that details how they are satisfying the hold harmless requirement. If Applicants seek to recover transaction-related costs in an existing formula rate that allows for such recovery within such five-year period, then that compliance filing must be filed in the section 205 docket in which the formula rate was approved by the Commission, as well as in the instant section 203 docket.¹²⁹ We also note that, if the Applicants seek to recover transaction-related costs in a filing within such five-year period, whereby Applicants are proposing a *new* rate (either a new formula rate or a new stated rate), then that filing must be made in a *new* section 205 docket as well as in the instant section 203 docket.¹³⁰ The Commission will notice such filings for

¹²⁶ Merger Policy Statement, FERC Stats. & Regs. ¶ 31,044 at 30,126.

¹²⁷ *Duke Energy*, 86 FERC ¶ 61,227, at 61,816 (1999) (citing *Mid-Louisiana Gas Company*, 7 FERC ¶ 61,316, at 61,682, *reh’g denied*, 8 FERC ¶ 61,227 (1979), *aff’d sub nom. Transcontinental Gas Pipe Line Corp. v. FERC*, 652 F.2d 179 (D.C. Cir. 1981)) (rate recovery of an existing facility is generally limited to the original cost of the facility).

¹²⁸ Public Utility Holding Company Act of 2005, 42 U.S.C. § 16451 *et seq.* (2006) (PUHCA 2005).

¹²⁹ In this case, the filing would be a compliance filing in both the section 203 and 205 dockets.

¹³⁰ In this case, the filing would be a compliance filing in the section 203 docket, but a rate application in the section 205 docket.

public comment. In such filings, Applicants must: (1) specifically identify the transaction-related costs they are seeking to recover, and (2) demonstrate that those costs are exceeded by the savings produced by the transaction, in addition to any requirements associated with filings made under section 205. Such a hold harmless commitment will protect customers' wholesale and transmission rates from being adversely affected by the Proposed Transaction.¹³¹

121. Accordingly, in light of these considerations and requirements, we find that the Proposed Transaction will not adversely affect rates.

3. Effect on Regulation

a. Applicants' Analysis

122. Applicants state that the Proposed Transaction will not have any impact on the jurisdiction of either this Commission or any state public utility commission over any of the Applicants or any of their affiliates or subsidiaries, each of which will remain subject to regulation after the Proposed Transaction closes to the same extent each was regulated before the closing of the Proposed Transaction.¹³²

b. Commission Determination

123. We find no evidence that either state or federal regulation will be impaired by the Proposed Transaction. The Commission's review of a transaction's effect on regulation focuses on ensuring that it does not result in a regulatory gap at the federal or state level.¹³³ We find that the Proposed Transaction will not create a regulatory gap at the federal level because the Commission will retain its regulatory authority over the companies after the transaction. The Commission stated in the Merger Policy Statement that it ordinarily will not set the issue of the effect of a transaction on state regulatory authority for a trial-type hearing where a state has authority to act on the transaction. However, if the state lacks this authority and raises concerns about the effect on regulation, the Commission stated that it may set the issue for hearing, and that it will address such circumstances on a case-by-case basis.¹³⁴ We note that no party alleges that

¹³¹ See *ITC Midwest LLC*, 133 FERC ¶ 61,169 at P 24-25; *FirstEnergy Corp.*, 133 FERC ¶ 61,222 at P 63; and *PPL Corp.*, 133 FERC ¶ 61,083 at P 26-27.

¹³² Application at 51-52.

¹³³ Merger Policy Statement, FERC Stats. & Regs. ¶ 31,044 at 30,124.

¹³⁴ *Id.* at 30,125.

regulation would be impaired by the Proposed Transaction, and no state commission has requested that the Commission address the issue of the effect on state regulation.

4. Cross-Subsidization

a. Applicants' Analysis

124. Applicants contend that the Proposed Transaction will not result in cross-subsidization of a non-utility associate company or the pledge or encumbrance of assets of a traditional public utility that has captive customers or that owns or provides transmission service over jurisdictional facilities for the benefit of an associate company. Specifically, Applicants verify that, based on the facts and circumstances known to them or that are reasonably foreseeable, the Proposed Transaction will not result in, at the time of the transaction or in the future: (1) any transfer of facilities between a traditional public utility associate company that has captive customers or that owns or provides transmission service over jurisdictional transmission facilities, and an associate company; (2) any new issuance of securities by a traditional public utility associate company that has captive customers or that owns or provides transmission service over jurisdictional transmission facilities, for the benefit of an associate company; (3) any new pledge or encumbrance of assets of a traditional public utility associate company that has captive customers or that owns or provides transmission service over jurisdictional transmission facilities, for the benefit of an associate company; or (4) any new affiliate contract between a non-utility associate company and a traditional public utility associate company that has captive customers or that owns or provides transmission service over jurisdictional transmission facilities, other than non-power goods and services agreements subject to review under sections 205 and 206 of the FPA.¹³⁵ Further, Applicants and their affiliates disclose their existing pledges and encumbrances of utility assets, as required under Order No. 669-A and 18 C.F.R. § 33.2(j)(1).

125. Applicants state that, while both Exelon and Constellation have significant unregulated merchant utility businesses, both companies have already put in place ring-fencing provisions that are designed to protect their operating utility subsidiaries from financial difficulties that may affect their unregulated affiliates. Applicants commit to keep the ring-fencing measures in place following the Proposed Transaction.¹³⁶

¹³⁵ Application at Exhibit M.

¹³⁶ *Id.*

b. Comments

126. IMEA states that additional safeguards are required to protect against proscribed cross-subsidization. IMEA claims the assurances given by Applicants are grounded on claims that the Proposed Transaction is a straight-forward merger that will not raise any improper subsidization concerns and that, in any event, existing “ring-fencing” provisions for their unregulated merchant utility business coupled with existing federal and state regulation will suffice to provide adequate protections.¹³⁷ IMEA goes on to state, quoting the application, that “for a merger that will result in ‘the nation’s leading customer supply business’ that will own or control ‘approximately 43,000 MW of generation capacity diversified across ten different geographic markets,’ more should be required.”¹³⁸ IMEA requests that Applicants provide the Commission public notice of exactly what state and federal safeguards they are invoking as suitable protections as well as any commitments made to governing states in this regard.¹³⁹

c. Commission Determination

127. Based upon our review of the representations as presented in the application, we determine that the Proposed Transaction will not result in cross-subsidization or the pledge or encumbrance of utility assets for the benefit of an associate company. We decline IMEA’s request to require additional information, as Applicants have met the requirements in the Commission’s regulations regarding cross-subsidization.¹⁴⁰

128. When a controlling interest in a public utility is acquired by another company, whether a domestic company or a foreign company, the Commission’s ability to protect public utility customers adequately against inappropriate cross-subsidization may be impaired unless it has access to the acquirer’s books and records. Section 301(c) of the FPA gives the Commission authority to examine the books and records of any person who controls, directly or indirectly, a jurisdictional public utility insofar as the books and records relate to transactions with or the business of such public utility. In addition, the merged company will be subject to record-keeping and books and records requirements of PUHCA 2005. The approval of the Proposed Transaction is based on such ability to examine books and records.

¹³⁷ IMEA Comments at 7.

¹³⁸ *Id.* at 8.

¹³⁹ *Id.*

¹⁴⁰ 18 C.F.R. ¶ 33.2(j) (2011).

5. Accounting Issues

a. Applicants' Analysis

129. Applicants state the Proposed Transaction is not anticipated to result in any adjustments to the books maintained by any Applicant that is required to keep its books in accordance with the Commission's Uniform System of Accounts (USofA) and, therefore, there are no pro forma accounting entries to provide. Applicants further state that, if they determine in the future that the Proposed Transaction were to impact the books of any such entity, they will submit the required accounting entries to the Commission within six months of the consummation of the Proposed Transaction.¹⁴¹

b. Comments

130. MD/PA Consumer Advocates assert that the Commission has expressly stated that it interprets the hold harmless rate commitment "to include all transaction-related costs, not only costs related to consummating the transaction." They argue if the Commission accepts the Applicants' commitment in this instance, it should again make clear that the commitment applies to all costs caused by the merger, which includes transaction as well as transition costs. They state that, in order to ensure that the Commission's mandate for the Applicants' commitment is followed, the Commission should direct the Applicants to record all of the Applicants' transaction and transition costs below the line in Account 426.5, Other Deductions, including incremental internal labor costs.¹⁴²

131. Applicants state they agree with MD/PA Consumer Advocates that their hold harmless commitment applies to all transaction-related costs, not only those related to consummating the transaction, and that it would be appropriate to record all transaction-related costs below the line in Account 426.5. However, Applicants disagree with MD/PA Consumer Advocates' assertion that the requirement to record expenses below the line in Account 426.5 should apply to transition related costs other than transaction costs. Applicants state that such treatment would be inconsistent with the Commission's recent holding in *BHE Holdings Inc.*, 133 FERC ¶ 61,231 (2010). They state that, in that case, the Commission limited the requirement to record costs in Account 426.5 to "[c]osts incurred to effectuate a merger." Finally, Applicants state that it would be inappropriate to record in Account 426.5 transition costs, such as integration costs, that

¹⁴¹ Application, Attachment 1.

¹⁴² MD/PA Consumer Advocates July 19 Comments at 14.

are not associated with the costs to effectuate a merger and/or that are operational in nature.¹⁴³

c. Commission Determination

132. Applicants claim that the Proposed Transaction will not impact the Commission jurisdictional accounts of any of their subsidiaries or affiliates. The Applicants also state that if the Proposed Transaction impacts the books of the any entity that is required to keep its books in accordance with the USofA, they will submit the required accounting entries. Therefore, to the extent that the Proposed Transaction affects the books of any jurisdictional entity required to keep its books in accordance with the USofA, the jurisdictional entity must account for the Proposed Transaction in accordance with Electric Plant Instruction No. 5, and Account 102, Electric Plant Purchased or Sold, of the USofA. Applicants shall submit their final accounting entries within six months of the date that the Proposed Transaction is consummated, and the accounting submission shall provide all the accounting entries and amounts related to the transaction along with narrative explanations describing the basis for the entries.

133. We also reject MD/PA Consumer Advocates' contention that all transaction and transition costs must be recorded in Account 426.5 pursuant to our accounting regulations. Should the merger impact any entity that is required to maintain its books and records in accordance with the USofA, we have required those entities to record the transaction costs in Account 426.5.¹⁴⁴ Transaction expenses are primarily legal, consulting, and professional services in nature that are incurred prior to the consummation of the merger. These types of expenses are not considered operating in nature. However, transition costs, such as integration costs and other operational costs incurred subsequent to the merger and incurred to effectuate savings are considered operational in nature. Therefore, we agree with the Applicants that it would be inappropriate to record in Account 426.5 transition costs such as integration costs. Transition costs are typically recorded in an operating expense account or capitalized in an asset account, as appropriate. This accounting however does not permit Applicants to recover any transaction or transition costs through their wholesale power or transmission rates during the hold harmless period without first making a section 205 filing and receiving authorization from the Commission, as discussed above.

¹⁴³ Applicants August 3 Answer at 15-16.

¹⁴⁴ See, e.g., *Midwest Power Systems, Inc. and Iowa-Illinois Gas and Electric Company*, 71 FERC ¶ 61,386 (1995); *NSTAR Electric and Gas Corporation*, Docket No. AC07-183-000 (Aug. 9, 2007) (unpublished letter order), and *BHE Holdings Inc.*, 133 FERC ¶ 61,231 (2010).

6. Other Issues

134. Information and/or systems connected to the bulk power system involved in this transaction may be subject to reliability and cyber security standards approved by the Commission pursuant to FPA section 215. Compliance with these standards is mandatory and enforceable regardless of the physical location of the affiliates or investors, information databases, and operating systems. If affiliates, personnel or investors are not authorized for access to such information and/or systems connected to the bulk power system, a public utility is obligated to take the appropriate measures to deny access to this information and/or the equipment/software connected to the bulk power system. The mechanisms that deny access to information, procedures, software, equipment, etc., must comply with all applicable reliability and cyber security standards. The Commission, the North American Electric Reliability Corporation or the relevant Regional Entity may audit compliance with reliability and cyber security standards.¹⁴⁵

The Commission orders:

(A) The Proposed Transaction is hereby conditionally authorized, as discussed in the body of this order.

(B) The foregoing authorization is without prejudice to the authority of the Commission or any other regulatory body with respect to rates, service, accounts, valuation, estimates, or determinations of cost, or any other matter whatsoever now pending or which may become before the Commission.

(C) Nothing in this order shall be construed to imply acquiescence in any estimate or determination of cost or any valuation of property claimed or asserted.

(D) The Commission retains authority under sections 203(b) and 309 of the FPA to issue supplemental orders as appropriate.

(E) Applicants shall make appropriate filings under section 205 of the FPA, as necessary, to implement the Proposed Transaction.

(F) Applicants must inform the Commission within 30 days of any material change in circumstances that would reflect a departure from the facts the Commission relied upon in authorizing the Proposed Transaction.

(G) Applicants shall notify the Commission within 10 days of the date on which the Proposed Transaction is consummated.

¹⁴⁵ See also *AEE, L.L.C.*, 130 FERC ¶ 62,205 (2010) (delegated order).

(H) If Applicants seek to recover Transaction-related costs through their wholesale power or transmission rates, they must first submit a compliance filing in this docket that details how they are satisfying the hold harmless requirement in addition to a section 205 filing. In particular, in such a filing, Applicants must: (1) specifically identify the Transaction-related costs they are seeking to recover; and (2) demonstrate that those costs are exceeded by the savings produced by the Transaction.

(I) To the extent that the Proposed Transaction affects any entity that is required to keep its books and records in accordance with the USofA, that entity must account for the Proposed Transaction in accordance with Electric Plant Instruction No. 5 and Account 102, Electric Plant Purchased or Sold. The entity shall submit its final accounting entries within six months from the date the Proposed Transaction is consummated, and the accounting submission shall provide all the accounting entries and amounts related to the Proposed Transaction along with narrative explanations describing the basis for the entries. If the entries are recorded after six months from the date the Proposed Transaction was consummated, the entity must file those entries with the Commission within 60 days from the date of recording such entries.

(J) Applicants must appoint an independent entity to verify that the bidding behavior in the Interim Mitigation Period is consistent with that to which Applicants have committed. Applicants must file a report, certified by the independent entity, within 10 days of the end of each quarter in which they retain ownership of the facilities to be divested.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.