146 FERC ¶ 61,196
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Cheryl A. LaFleur, Acting Chairman;
Philip D. Moeller, John R. Norris,
and Tony Clark.

NRG Energy Holdings, Inc. Docket No. EC14-14-000
Edison Mission Energy

ORDER AUTHORIZING PROPOSED TRANSACTION

(Issued March 18, 2014)

1. On October 25, 2013, NRG Holdings, Inc. (NRG Holdings) and Edison Mission Energy (Edison Mission) and its public utility subsidiaries (Edison Mission Public Utilities) (collectively, Applicants) filed an application under sections 203(a)(1)(A) and 203(a)(1)(B) of the Federal Power Act (FPA)[1] requesting authorization of a transaction in which NRG Holdings will acquire substantially all of the assets of Edison Mission, including Edison Mission's direct and indirect interests in its public utility subsidiaries, in exchange for cash and stock (Proposed Transaction). The Commission has reviewed the Proposed Transaction under the Commission's Merger Policy Statement.[2] As discussed below, we will authorize the Proposed Transaction as consistent with the public interest.

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[1] 16 U.S.C. § 824b (2012).

[2] *See 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 Federal Power Act Section 203*, Order No. 669, FERC Stats. & Regs. ¶ 31,200 (2005), *order on reh'g*, Order No. 669-A, FERC Stats. & Regs. ¶ 31,214 (2006), *order on reh'g*, Order No. 669-B, FERC Stats. & Regs. ¶ 31,225 (2006).

I. Background

2. On December 17, 2012, Edison Mission and certain of its affiliated entities, including Midwest Generation, LLC (Midwest Generation), initiated a proceeding under Chapter 11 of the Bankruptcy Code in the United States Bankruptcy Court for the Northern District of Illinois Eastern Division (Bankruptcy Court). Applicants state that Commission approval of the Proposed Transaction will facilitate the timely reorganization of Edison Mission and certain of its subsidiaries under the Bankruptcy Code and facilitate certain payments to their creditors under a proposed plan for reorganization filed with the Bankruptcy Court. Applicants state that the Proposed Transaction will resolve all the issues in the bankruptcy and allow Edison Mission to exit bankruptcy proceedings in the early part of 2014. Applicants state that the Proposed Transaction is supported by the major stakeholders in the bankruptcy proceeding.

3. Applicants also state that, when the Proposed Transaction is consummated, the issues pending before the Commission in Docket No. EC13-103-000, in which Midwest Generation filed an application for section 203 authorization to relinquish control over certain facilities, will be moot. In that docket, Midwest Generation stated that it would reject its leases of the Powerton and Joliet Stations under section 365 of the Bankruptcy Code, reverting control to the facilities' lessors. On November 1, 2013, at Midwest Generation's request, the Commission tolled Midwest Generation's application in order consider the Proposed Transaction in this proceeding.[3] As part of the Proposed Transaction in this proceeding Midwest Generation will assume the leases of the facilities, which Applicants state will allow Midwest Generation to withdraw its application in Docket No. EC13-103-000.

A. Description of the Parties

1. NRG Holdings and Affiliates

4. NRG Holdings is a corporation formed for the purposes of effecting the Proposed Transaction and is a wholly-owned subsidiary of NRG Acquisition Holdings Inc., which is also a corporation formed for the purpose of effecting the Proposed Transaction, and is a wholly-owned subsidiary of NRG Entergy, Inc. (NRG). NRG is a publically-held corporation and an integrated wholesale power generation and retail electricity company. NRG engages in three related electric businesses through various subsidiaries: (1) wholesale power generation and electricity and fuel trading; (2) retail electric supply and demand response; and (3) deployment and commercialization of alternative energy technologies. NRG owns or controls over 46,000 megawatts (MW) of electric generating

[3] *See Midwest Generation, LLC*, 145 FERC ¶ 61,094 (2013).

capacity throughout the United States. NRG owns a number of these subsidiaries through NRG Yield, Inc. (NRG Yield), which is a publically-traded company in which NRG owns 66.5 percent of the voting shares. NRG and NRG Yield have subsidiaries that own or control generation in the following markets: (1) California Independent System Operator Corporation (CAISO); (2) PJM Interconnection, L.L.C. (PJM); and (3) Midcontinent Independent System Operator, Inc. (MISO).

2. Edison Mission

5. Edison Mission is a wholly-owned subsidiary of Mission Energy Holding Company, which is a wholly-owned subsidiary of Edison Mission Group Inc. (EMG). EMG is a subsidiary of Edison International. Through various subsidiaries and affiliates, Edison Mission is engaged in the business of operating, owning or leasing, acquiring, developing, and selling energy and capacity from independent power production facilities and in hedging and trading activities. Edison Mission owns or controls over 8,000 MW of electric generation facilities through the United States. Edison Mission is also affiliated with Southern California Edison Company (Southern California Edison), which owns transmission facilities under the operational control of CAISO and has ownership interests in generation facilities in and around California. Edison Mission's direct and indirect subsidiaries own generation in the following markets: (1) CAISO; (2) PJM; (3) MISO; (4) Nebraska Public Power District Balancing Area Authority (BAA); (5) Oklahoma Gas and Electric Company BAA; (6) PacifiCorp East BAA; (7) Public Service Company of New Mexico BAA; (8) Southwestern Public Service BAA; (9) Upper Great Plains Region BAA; and (10) Western Farmers Electric Cooperative BAA.

B. Description of the Proposed Transaction

6. The terms of the Proposed Transaction are set forth in the Asset Purchase Agreement, under which NRG Holdings will acquire substantially all of the assets of Edison Mission, including its direct and indirect interests in the Edison Mission Public Utilities and other subsidiaries, for an aggregate purchase price of $2,635 million (including retained cash within Edison Mission). The aggregate purchase price will consist of NRG common stock and cash payments. Additionally, NRG Holdings will assume certain liabilities of Edison Mission and its subsidiaries, and NRG will also guarantee certain obligations related to Midwest Generation.

7. Under the terms of the Asset Purchase Agreement, Edison Mission will retain the rights to market and sell "Non-Core" assets to third parties for which the proceeds received by Edison Mission do not exceed $25 million individually or $50 million in the aggregate. Edison Mission commits to separately seek approval under section 203 of the FPA, if required, for any such transactions. Applicants have assumed that NRG Holdings will assume all such assets for the purpose of this Application.

II. Notice of Filing and Responsive Pleadings

8. Notice of the Application was published in the *Federal Register*, 78 Fed. Reg. 65,636 (2013), with interventions and comments due on or before November 15, 2013. Notice of the Applicants' errata was published in the *Federal Register*, 78 Fed. Reg. 67,138 (2013), with interventions and comments due on or before November 15, 2013.[4] On October 30, 2013, the Commission issued an errata notice to correct the comment date to December 9, 2013.

9. The following entities filed motions to intervene: Bank of New York Mellon, as Indenture Trustee; Exelon Corporation; FC Energy Finance I, Inc.; Nesbitt Asset Recovery Series P-1, Powerton Trust II, Nesbitt Asset Recovery Series J-1, and Joliet Trust II ; Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor for PJM (Market Monitor); the PJM Industrial Customer Coalition; Powerton Generation II, LLC and Joliet Generation II, LLC; and the Senior Noteholder Committee.

10. The Official Committee of Unsecured Creditors of Edison Mission (Unsecured Creditors) filed a motion to intervene and comments in support of the Application as a necessary step toward consummating the Bankruptcy Court proceedings.[5] The Market Monitor filed comments (Market Monitor's December Comment).

11. On December 5, 2013, the Director of the Division of Electric Power Regulation – West issued a request for additional information from Applicants.[6] On December 11, 2013, Applicants submitted a timely response to the Deficiency Letter.[7] Notice of the Applicants' response was published in the *Federal Register*, 78 Fed. Reg. 77,669 (2013), with interventions and comments due on or before January 2, 2014. The Market Monitor filed comments on January 2, 2014, and filed corrections to its comments on January 6, 2014.

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[4] Applicants' errata corrected two errors in the organizational charts provided in Exhibit C of the Application.

[5] Unsecured Creditors Comments at 3.

[6] Letter order directing Applicants to provide additional information, Docket No. EC14-14-000 (Dec. 5, 2013) (Deficiency Letter).

[7] Response to Deficiency Letter, Docket No. EC14-14 (filed Dec. 11, 2013) (Applicants' Response to Deficiency Letter).

12. Applicants filed answers to the Market Monitor's comments to the Application (Applicants' December Answer) and the Response (Applicants' January Answer). The Market Monitor filed an answer (Market Monitor's Answer) to the Applicants' answers. Applicants filed a limited answer to the Market Monitor's Answer, stating that their previous filings address the issues raised by the Market Monitor and that they would not file any further comments.[8]

13. On February 27, 2014, Applicants, Unsecured Creditors, the Senior Noteholder Committee, Nesbitt Asset Recovery Series P-1, Nesbitt Asset Recovery Series J-1, Powerton Generation II, LLC, Joliet Generation II, LLC, Bank of New York Mellon, Joliet Trust II, and Powerton Trust II filed a joint request for expedited action.

III. Discussion

A. Procedural Issues

14. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2013), the timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding.

15. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2013), prohibits an answer to a protest or an answer unless otherwise ordered by the decisional authority. We will accept Applicants' and the Market Monitor's Answers because they have provided information that assisted us in our decision-making process.

B. Standard of Review Under Section 203

16. Section 203(a)(4) of the FPA requires the Commission to approve a transaction if it finds that the transaction "will be consistent with the public interest."[9] The Commission's analysis of whether a transaction is consistent with the public interest generally involves the consideration of three factors: (1) the effect on competition; (2) the effect on rates; and (3) the effect on regulation.[10] Section 203(a)(4) also requires the Commission, before granting authorization, to find that the transaction "will not result in cross-subsidization of a non-utility associate company or the pledge or encumbrance of

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[8] Applicants' January 24, 2014 Answer at 1.

[9] 16 U.S.C. § 824b(a)(4) (2012).

[10] *See Merger Policy Statement*, FERC Stats. & Regs. ¶ 31,044 at 30,111.

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."[11] The Commission's regulations establish verification and informational requirements for applicants that seek a determination that a transaction will not result in inappropriate cross-subsidization or a pledge or encumbrance of utility assets.[12]

C. Analysis Under Section 203

1. Effect on Horizontal Competition

a. Applicants' Analysis

17. Applicants argue that the Proposed Transaction raises no concerns with respect to horizontal market power. As discussed below, Applicants analyzed the effect of the Proposed Transaction in the MISO, PJM, and CAISO markets (Relevant Geographic Markets), the only Commission jurisdictional markets in which the generation of NRG and its affiliates, and that of Edison Mission's subsidiaries, overlap.[13] They additionally examine the effect of the Proposed Transaction on competition in PJM for installed capacity. Finally, they examine the effect of the Proposed Transaction on competition in the markets for regulation capability (or imbalance energy), spinning or synchronized reserves, and non-spinning reserves or day-ahead scheduling reserves.[14]

18. Applicants performed delivered price tests (DPTs) to analyze the energy markets in the Relevant Geographic Markets using both the available economic capacity and the economic capacity measures of capacity.[15] Applicants performed DPTs for short-term energy and capacity markets for 12 market conditions, differentiated by season and by load level. The seasons are Spring/Fall, Summer, and Winter. For each season, the

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[11] 16 U.S.C. § 824b(a)(4).

[12] 18. C.F.R. § 33.2(j) (2013).

[13] Application at 47.

[14] Application, Morris Affidavit at 11.

[15] Each supplier's "economic capacity" is the amount of capacity that could compete in the relevant market given market prices, running costs, and transmission availability. "Available economic capacity" is based on the same factors but subtracts the supplier's native load obligation from its capacity and adjusts transmission availability accordingly.

market conditions correspond to: (1) the top five percent of on-peak load hours; (2) the next 10 percent of on-peak load hours; (3) the remaining on-peak load hours; and (4) off-peak load hours.[16]

19. Applicants base their DPT results upon historical electric power market prices and fuel prices from 2011-2012. Applicants reason that these prices are the best way to match fuel prices to actual electric power prices. Based on this analysis, Applicants provided price sensitivities on increasing and decreasing market prices by 10 percent. Applicants performed an additional sensitivity based on forward prices for natural gas and estimated electric market prices based on those forward prices. Applicants consider this analysis to be less reliable because forward prices often "provide a biased measure of expected future prices."[17]

20. Starting with PJM, Applicants analyzed only the entire PJM market.[18] Applicants' results for economic capacity show increases in the Herfindahl-Hirschman Index (HHI) ranging from 29 to 35 points in an unconcentrated market.[19] Applicants note that available economic capacity does not provide a meaningful measure of competition in

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[16] Application, Morris Affidavit at 15.

[17] *Id.* at 23.

[18] Applicants did not study any of the Commission-recognized submarkets (PJM East, PJM East of 5004/5005, or PJM East of AP South) because Edison Mission neither owns nor controls any generation nor has any firm transmission rights in any of these areas. Application at 51.

[19] *Id.* at 50. 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 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; s*ee also Analysis of Horizontal Market Power under the Federal Power Act*, 138 FERC ¶ 61,109 (2012) (affirming the Commission's use of the thresholds adopted in the *Merger Policy Statement*).

restructured electric power markets such as PJM. Nevertheless, Applicants performed DPTs for available economic capacity in PJM. Applicants state that they found HHI increases ranging from 70 to 225 points in an unconcentrated market, indicating that the Proposed Transaction is unlikely to result in NRG having market power.[20] Applicants' plus- and minus 10 percent price sensitivities for PJM likewise showed no screen failures for economic capacity.[21]

21. Applicants also presented results for PJM's centralized competitive installed Reliability Pricing Model (RPM) Capacity Market. To examine potential effects of the Proposed Transaction on competition in the RPM Capacity Market, Applicants present information based upon total unforced capacity (UCAP)[22] for PJM. Applicants find that the Proposed Transaction results in a 48 point increase in the HHI for the RPM in an unconcentrated market, and thus state that the Proposed Transaction does not raise competitive concerns in the RPM Capacity Market in PJM.[23]

22. Applicants argue that the Proposed Transaction does not harm competition in PJM's ancillary service markets. PJM simultaneously runs markets for regulation (Regulation Market), synchronized reserve (Synchronized Reserve Market), and energy (Energy Market). A unit can bid into both the Regulation and Synchronized Reserve Markets and can be selected for one, but not for both. To fulfill their regulation obligation, load-serving entities have the alternatives of purchasing from the Regulation Market, self-scheduling their own resources, or contracting with other market participants.[24]

23. Applicants state that in PJM, NRG Holding's plants have regulation capability totaling 703 MW, and Edison Mission's plants have regulation capability totaling 105 to 165 MW, depending on unit ramp rates. They state that in 2012, NRG made regulation sales of 445,018 megawatt-hours (MWh), or 5.5 percent of market sales, and Edison

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[20] Application, Morris Affidavit at 21.

[21] Application, Exhibit J8 at 1.

[22] UCAP is defined as installed capacity rated at summer conditions that are not on average experiencing a forced outage or forced de-rating, calculated for each Capacity Resource without regard to the ownership of or the contractual rights to the capacity of the unit. Application, Morris Affidavit at 24.

[23] *Id.* at 25.

[24] *Id.* at 26.

Mission made regulation sales of 453,256 MWh, or 5.6 percent of market sales.[25] Applicants computed an HHI change of 62 points in the Regulation Market attributable to the Proposed Transaction in a moderately concentrated market (post-transaction HHI = 1,797). Applicants therefore conclude that the Proposed Transaction passes the Commission's screening threshold in the Regulation Market. Applicants further note that the Regulation Market has significant excess supply: the ratio of offered and eligible regulation to regulation required averaged 3.61 in 2012.[26] Applicants argue that this makes it unlikely that any one market participant would find it profitable to withhold services. Applicants further submit that to guard against the use of market power, market participants make cost-based offers and have the option of making price-based offers that are capped at $100/MWh.[27]

24. NRG's generators located in PJM have synchronized reserve capability totaling 1,690 MW, and Edison Mission's plants have synchronized reserve capability totaling 124 to 128 MW, depending on unit ramp rates. Applicants state that due to the large amount of online (Tier 1) synchronized reserves available, PJM's synchronized reserve requirement is usually met with Tier 1 reserves, and the synchronized (Tier 2) reserve market does not have to be cleared.[28] In 2012, the latter was cleared in two percent of the hours.[29] In 2012, NRG made sales of 35,220 MWh, or 0.3 percent of market sales, and

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[25] According to Applicants, the average hourly regulation demand in PJM was 921 MW in 2012, yielding 8,067,960 MWh. *Id.* (citing Independent Market Monitor for PJM, *State of the Market Report for PJM* 2167 (Mar. 2013) (2012 State of the Market Report for PJM), *available at* http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2012/2012-som-pjm-volume1.pdf).

[26] Applicants state that the 2012 State of the Market Report for PJM indicates that the average hourly regulation demand in PJM was 921 MW in 2012, yielding 8,067,960 MWh. Further, the same report indicates that an hourly average HHI is 1,735 based on actual services provided. Applicants state that there is a wide range of hourly HHIs, with a mode around 1,250, implying that the hourly HHI level is typically below 1,735. *Id.* at 26 (citing 2012 State of the Market Report for PJM at 267, 275).

[27] *Id.*

[28] Tier 1 resources are units that are currently in operation (online). Tier 2 resources are resources that bid into the reserve market, but are not currently online.

[29] *Id.* at 27 (citing 2012 State of the Market Report for PJM at 282).

Edison Mission made sales of 1,164 MWh, or 0.001 percent of total market sales of 11,856,000 MWh. The HHI change for this market rounds to zero.[30]

25. Applicants state that Edison Mission's generators have day-ahead scheduling reserve capability totaling 450 to 495 MW, depending on unit ramp rates. In 2012, NRG made sales of 547,176 MWh, or 0.9 percent of market sales, and Edison Mission made sales of 429,437 MWh, or 0.7 percent of total market sales of 59,927,160 MWh.[31] The HHI change for this market is equal to one point.

26. In summary, Applicants state that they sell negligible synchronized reserves and day-ahead scheduling reserves to the markets in PJM. Although the Regulation Market is moderately concentrated, the change in HHI is less than 100. Applicants submit that the Proposed Transaction therefore will not create or enhance their market power in any ancillary services markets in PJM.[32]

27. Applicants performed DPTs for the CAISO market using both economic capacity and available economic capacity. Applicants found that the Proposed Transaction resulted in HHI increases for economic capacity ranging from zero to 14 points in an unconcentrated market. Using available economic capacity, the Proposed Transaction results in HHI increases for the 12 time periods Applicants studied, ranging from zero to 61 points in a market that the post-transaction HHIs show to be unconcentrated or moderately concentrated. Applicants argue that the results of the DPT analysis demonstrate that the Proposed Transaction will not have an adverse effect on competition in the CAISO market.[33] Applicants' plus- and minus 10 percent price sensitivities for CAISO likewise showed no screen failures for economic capacity.[34]

28. CAISO operates markets for four types of ancillary services: regulation up, regulation down, spinning reserves, and non-spinning reserves.[35] NRG's generators have

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[30] *Id*. Applicants state that these sales include both Tier 1 and Tier 2 reserves.

[31] *Id.* (citing 2012 State of the Market Report for PJM at 289).

[32] *Id.*

[33] Application at 51.

[34] Application, Exhibit J8 at 2.

[35] A generator may bid its regulation capacity into either the regulation down market (i.e., decrease its output when called to do so) or the regulation up market (i.e., increase its output when called to do so).

regulation capability totaling 3,208 MW in the CAISO market, while Edison Mission's plants had regulation capability totaling 54 MW in 2012. Applicants state that in 2012, NRG made regulation sales of 198,208 MWh, which was three percent of total sales of 3,057,240 MWh. Although Edison Mission's generators may have made some regulation sales in 2012, those sales would be attributed to Southern California Edison as scheduling coordinator, rather than to Edison Mission.[36]

29. Applicants state that in 2012, NRG's plants in CAISO had spinning reserve capability totaling 3,419 MW, and Edison Mission's plants had spinning reserve capability totaling 44 MW. In 2012, NRG made spinning reserve sales of 36,811 MWh, which was 0.5 percent of market sales. Applicants state that although Edison Mission's plants may possibly have made some reserve sales in 2012, those sales would be attributed to Southern California Edison, the scheduling coordinator, rather than to Edison Mission.[37]

30. Applicants state that in 2012, NRG's plants in CAISO had non-spinning reserve capability totaling 1,779 MW, and Edison Mission's plants did not have non-spinning reserve capability. In 2012, NRG made non-spinning reserve sales of 47,549 MWH, which was 0.6 percent of market sales.[38] Applicants conclude that NRG provides negligible ancillary services and most of Edison Mission's ancillary services are under the control of the local utility, which is also the contract counterparty. Applicants argue that given these facts, the Proposed Transaction will not create or enhance market power of Applicants in any ancillary services markets in California.[39]

31. Applicants argue that the extent of the business transactions of the combining entities in the MISO market is *de minimis*, regardless of whether they assume that Entergy Corporation (Entergy) and Cleco Power LLC (Cleco) have been integrated into MISO.[40] Applicants state that the Proposed Transaction increases the market share of NRG and its affiliates from approximately 2.9 percent to approximately 3.1 percent of

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[36] Application, Morris Affidavit at 28.

[37] *Id.*

[38] *Id.* at 28-29.

[39] *Id.* at 29.

[40] Application at 48-49. MISO completed integrating the transmission systems of Entergy and Cleco on December 18, 2013. Therefore, we focus our attention on Applicants' analysis of this broader market.

total capacity in the MISO market, even if they conservatively disregard the fact that much of the generation capacity of the Edison Mission subsidiaries is committed to non-affiliates under long-term contracts.[41]

32. Even though Applicants view the Proposed Transaction to have a *de minimis* impact on horizontal market power in the MISO market, Applicants performed a DPT out of an "abundance of caution." Applicants find that the HHI increases for the 12 time periods studied are all three points or lower in an unconcentrated market.[42]

b. **Deficiency Letter and Response**

33. Commission staff sought additional information on the impact of the Proposed Transaction on horizontal market power. Specifically, staff asked Applicants to:

i. "[R]e-run the sensitivity case (increasing and decreasing market prices by 10 percent) studies using expected future prices that are 'as forward-looking as practicable', and to provide the results for each study, the prices used in each study, and the studies themselves."[43]

ii. "Explain why the top five percent of on-peak load hours is an appropriate assumption for the price during the summer super peak 1 hour in both the PJM market and the CAISO market, and provide a sensitivity run using the top 1 percent of on-peak load hours or top load hour in Summer Super Peak 1 for each market."[44]

34. In their Response, Applicants reiterate that they performed their base case analyses in a manner that ensured that their results were as reliable and forward-looking as possible with respect to future fuel costs and associated electric energy prices. Applicants state that they included a sensitivity analysis based upon forward prices for natural gas and electric market price forecasts. However, Applicants argue that this analysis is unreliable because the market price forecasts are unreliable.[45]

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[41] *Id.* at 49.

[42] *Id*.

[43] Deficiency Letter at 2.

[44] *Id.*

[45] Applicants' Response to Deficiency Letter at 2.

35. Applicants performed additional DPTs based on forward prices for fuel costs and adjusted electric Energy Market prices, with electric energy prices 10-percent higher and 10-percent lower, incorporating price forecasts. For the plus-10-percent PJM price sensitivity for economic capacity, Applicants found HHI changes ranging from 29 to 34 points in an unconcentrated market. Likewise, for the minus-10-percent price sensitivity, Applicants found HHI changes ranging from 27 to 35 points in an unconcentrated market. For available economic capacity in PJM, Applicants found HHI changes ranging from 62 points to 222 points and from 75 points to 216 points for their plus-10 percent and minus-10 percent price sensitivities, respectively, in unconcentrated markets.[46]

36. For economic capacity in CAISO, Applicants found HHI changes ranging from zero to 20 points and zero to 22 points for plus-10 percent and minus-10 percent price sensitivities, respectively, in markets that were moderately concentrated in one time period, and unconcentrated in all others. Likewise, for available economic capacity in CAISO, Applicants found HHI changes ranging from negative-22 points to 58 points in markets that were unconcentrated in eight time periods and moderately concentrated otherwise for their plus-10 percent price sensitivity. For their negative-10 percent price sensitivity, Applicants found HHI changes ranging from minus-five points to 58 points in markets that were unconcentrated in seven time periods and otherwise moderately concentrated.[47]

37. With respect to Staff's request that Applicants explain their rationale for using the top five percent of prices, Applicants quote the Merger Policy Statement, stating that applicants "should present separate analyses for each of the **major periods** when supply and demand conditions are similar."[48] Applicants maintain that they regard the top five percent of prices as the smallest "major period." They maintain that this approach is consistent with the fact that most economic decisions in electric power markets are typically made in advance of an hour and generation companies must consider the effects of their actions over a range of conditions.[49]

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[46] Applicants' Response to Deficiency Letter, Attachment A at 1, 3.

[47] Applicants' Response to Deficiency Letter at 2, 4.

[48] *Id.* at 3 (quoting *Merger Policy Statement,* FERC Stats. & Regs. 31,044 at 30,130 (emphasis added)).

[49] *Id.*

38. Nevertheless, Applicants performed additional DPTs based on the top one percent of prices for economic capacity base case; economic capacity, 10-percent price increase; economic capacity, 10-percent price decrease; available economic capacity, base case; available economic capacity, 10-percent price increase; available economic capacity, 10-percent price decrease; available economic capacity, based on forward prices for fuel costs and adjusted electric energy market prices; available economic capacity, forward prices, 10-percent price increase, and available economic capacity, forward prices, 10-percent price decrease. Applicants' results showed HHI changes of 10 to 59 points in an unconcentrated market.[50]

c. Market Monitor's December Comment

39. The Market Monitor performed an independent analysis of the impact of the Proposed Transaction on competition in PJM, using current market data. The Market Monitor uses three basic metrics in order to evaluate the impact of the Proposed Transaction: (1) market share; (2) HHI; and (3) the three pivotal supplier test, which is defined below. The Market Monitor concludes that the Proposed Transaction would increase concentration in a specific, highly concentrated PJM locational energy market and would increase concentration in the RPM Capacity Market and the Regulation Market, as discussed below. Therefore, the Market Monitor recommends that the Commission require behavioral mitigation to resolve these competitive concerns.[51]

40. The Market Monitor views a relevant energy market for its analysis as one defined by a constraint which is binding for 100 or more hours in the 2012-2013 planning year. Likewise, relevant ancillary services markets are those defined by the actual operation of PJM markets over the 2012-2013 planning year. The Market Monitor delineates relevant capacity markets as those that resulted from the actual operation of the markets for the 2015/2016 and 2016/2017 delivery years.[52]

41. The Market Monitor explains that the three pivotal supplier test is a residual supplier index used in the PJM markets to define locational market power. It explains that a three pivotal supplier test score that is less than 1.00 indicates a failure of the test. The Market Monitor states that the three pivotal supplier test explicitly incorporates the impact of excess supply and implicitly accounts for the impact of price elasticity of demand in the market power tests. The Market Monitor states that, unlike the DPT, the

[50] Applicants' Response to Deficiency Letter, Attachment A at 5.

[51] Market Monitor's December Comment at 2.

[52] Market Monitor's December Comment, Attachment A at 2.

three pivotal supplier test includes all offers with costs less than, or equal to, 1.50 times the clearing price for the local market. The Market Monitor believes that the three pivotal supplier test for local market power strikes a reasonable balance between the requirement to limit extreme structural market power and the goal of limiting intervention in markets when competitive forces are adequate.[53]

42. The Market Monitor states that the results of the three pivotal supplier test can differ from the results of the HHI and market share tests. It states that the three pivotal supplier test can show the existence of structural market power when the HHI is less than 2,500 and the maximum market share is less than 20 percent. Likewise, the three pivotal supplier test can show the absence of market power when the HHI is greater than 2,500 and the maximum market share is greater than 20 percent. The Market Monitor argues that the three pivotal supplier test is more accurate than the HHI and market share tests because it focuses on the relationship between demand and the most significant aspect of the ownership structure of supply available to meet it.[54]

43. The Market Monitor identified the Lanesville market as a defined locational energy market affected by the Proposed Transaction. The Market Monitor found that, pre-transaction, NRG or Edison Mission supplied energy to provide "raise help constraint relief"[55] for the Lanesville market in 229 peak hours and 54 off-peak hours. Pre-transaction NRG failed the three pivotal supplier test for the Lanesville market in 10 peak-hours and one off-peak hour, while Edison Mission failed the three pivotal supplier test for the Lanesville market in 228 peak and 54 off-peak hours. The Market Monitor discovered that the Proposed Transaction would have no impact on the number of hours that participants in the Lanesville market for "raise help constraint relief" would fail the three pivotal supplier test.[56]

44. The Market Monitor performed an HHI analysis on the Lanesville market as well. The Market Monitor's analysis indicates that the Proposed Transaction increased the HHI for the average peak market hour from 8,033 to 8,053; it found no change for the average off-peak HHI; and it found that the HHI for all hours increased from 7,836 to 7,890. The Market Monitor further found that of the 277 pre-merger Lanesville market event hours

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[53] *Id.* at 9-10.

[54] *Id.* at 10.

[55] "Raise help constraint relief" refers to incremental supply available to relieve (resolve) the constraint. *See id.* at 13-14.

[56] *Id.* at 14-15.

with an HHI of 4,000 or more, the Proposed Transaction would cause 11 of these market event hours to have an increase of 200 or more points and 10 of these market event hours to have an increase of 300 or more points.[57]

45. With respect to the RPM Capacity Market, the Market Monitor states that from time-to-time, transmission constraints create local capacity markets in specific RPM Locational Deliverability Areas (LDAs). It asserts that in these circumstances, when the three pivotal supplier test is failed, there is structural market power in the local market in question.[58]

46. The Market Monitor states that the RPM Capacity Market is, by design, always tight in the sense that total supply is generally only slightly larger than demand. The demand for capacity includes expected peak load plus a reserve margin. Thus, the reliability goal is to have total supply equal to, or slightly above, the demand for capacity. Further, the Market Monitor states that demand is almost entirely inelastic because the market rules require loads to purchase their share of the system capacity requirement. The result is that any supplier that owns more capacity than the difference between total supply and the defined demand is pivotal and has market power. The Market Monitor argues that the market design for capacity thus leads to structural market power. Therefore it argues that, given the basic features of market structure in the RPM Capacity Market, the potential for the exercise of market power is high.[59]

47. The Market Monitor states that the RPM Capacity Market has explicit market power mitigation rules designed to permit competitive, locational capacity prices while limiting the exercise of market power. It asserts that the RPM construct is consistent with the appropriate market design objectives of permitting competitive prices to reflect local scarcity conditions while explicitly limiting market power. Therefore, it states that the RPM Capacity Market design provides that competitive prices can reflect locational scarcity while not relying on the exercise of market power to achieve that design objective by limiting the exercise of market power via the application of the three pivotal supplier test and the resultant offer capping. The Market Monitor reasons, though, that one must also recognize that the market power mitigation rules are not perfect and cannot prevent all exercises of market power.[60]

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[57] *Id.* at 15-16.

[58] *Id.* at 16-17.

[59] *Id.* at 18-19.

[60] *Id.* at 19.

48. The Market Monitor calculated pre- and post-merger HHIs for the 2015/2016 and 2016/2017 RPM Base Residual Auctions for the markets cleared in the RPM Capacity Market (the "Total Market Analysis"[61]). The Market Monitor states that there was a change in the HHI for the PJM RTO-wide market (PJM Market) alone (and no submarkets). For 2015/2016 and 2016/2017, the changes in the HHI were 31 and 28 points, respectively, in an unconcentrated market.[62]

49. The Market Monitor also performed an "Incremental Market Analysis" for capacity in PJM, which addresses the ability of owners to exercise market power in the Capacity Market.[63] The Market Monitor found three pivotal supplier test scores for all identified markets to be less than 1.00, both pre- and post-merger, indicating failure of the test. Its test results showed that the Proposed Transaction resulted in changes in the test scores for the entire PJM market alone. For 2015/2016, the test score fell from 0.540 to 0.535, a change of 0.9 percent. For 2016/2017, the score fell from 0.586 to 0.568, a change of 3.1 percent.[64]

50. The Market Monitor states that the analysis of the impact of the Proposed Transaction on the Regulation Market examines the Regulation Market hours when either Edison Mission or NRG supplied and cleared regulation MW in the period from October 2012 through October 2013. It states that the Regulation Market affected by

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[61] *Id.* at 21. The Market Monitor states that the total market analysis addresses the incentive to exercise market power in the defined markets by analyzing ownership of capacity resources in LDAs who receive the clearing price.

[62] *Id.*

[63] The Market Monitor explains that the incremental supply available to meet the incremental demand when locational incremental demand must be met by capacity resources within the LDA defines a constrained LDA. It also defines the RTO market to include all supply that is not incremental supply in a constrained LDA. The RTO market includes all MW that resulted in the clearing price for the rest of the RTO. The three pivotal supplier test measures the degree to which the supply from three suppliers of capacity is required in order to meet the demand in an LDA. Two key variables in the incremental market analysis are the demand and the supply. The demand consists of the incremental MW of capacity required to relieve a constraint or clear a market. The supply consists of the incremental MW of supply available to relieve the constraint or clear the market. *Id.*

[64] *Id.* at 22.

NRG and Edison Mission resources is highly concentrated. In pre-merger terms, 63.4 percent of the market hours affected by NRG and Edison Mission resources had an HHI of 1,800 or more and 28.7 percent of the market hours had an HHI of 2,500 or more. The Market Monitor found that post-merger, 66.3 percent of these market hours would have had an HHI of 1,800 or more, and 28.9 percent of the market hours would have had an HHI of 2,500 or more. Further, it found that the Proposed Transaction would have caused the HHI to increase by 50 or more points in 268 of the 5,505 market hours whose pre-transaction HHI was 2,000 or more. Of these 268 hours, 140 displayed an HHI increase of 100 or more points, 53 had an increase of 200 or more points, and 29 had an increase of 300 or more points.[65]

51. The Market Monitor recommends that the Commission consider mitigation to address its limited, but not inconsequential, concerns. It believes that behavioral mitigation, in the form of requiring Applicants to engage in competitive offer behavior in each PJM market, would adequately address its concerns regarding the competitiveness of PJM's markets.[66]

d. Applicants' December Answer

52. Applicants answer that the Market Monitor December Comment largely confirms their Application and state that the Proposed Transaction "will have no substantial effects on competition in the Energy, RPM Capacity, or Regulation markets."[67] Applicants assert that many of the analyses presented by the Market Monitor do not offer meaningful information for addressing the competitive effects of the Proposed Transaction. For example, the Market Monitor does not provide standards to serve as benchmarks for the three pivotal supplier test.[68] Furthermore, Applicants state that the Market Monitor does not rely on the Commission's methodology to analyze the effects of the transaction, and instead relies on an "extremely exacting analysis."[69]

53. Applicants state that, even using its more comprehensive analysis, the Market Monitor only identified the Lanesville market as a relevant constraint in the Energy

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[65] *Id.* at 23.

[66] Market Monitor's December Comment at 2.

[67] Applicants' December Answer at 2.

[68] Applicants' December Answer, Morris Affidavit at 3.

[69] *Id.* at 5.

Market and there is no material increase in market concentration in the Lanesville market or any other PJM Energy Market.[70] However, Applicants dispute that the Lanesville market is still a binding constraint because they assert that the Market Monitor relies on obsolete data.[71] Applicants state that MISO substantially upgraded the Lanesville flowgate and that PJM has not reported a single constraint hour since March 14, 2013.[72]

54. Applicants also assert that, even if MISO did not upgrade the facility, the Market Monitor's results do not show any competitive effects from the Proposed Transaction. They state that the Market Monitor's results acknowledge that the Proposed Transaction does not result in an increase in the number of hours that the Lanesville market fails the three pivotal supplier test and therefore has no impact on the automatic mitigation for dispatch decisions.[73] Furthermore, Applicants state that the Market Monitor's calculated HHIs show that there were only 11 hours with an increase of 50 or more points, indicating that there are no competitive issues.[74]

55. Applicants also dispute that the "Lanesville market for 'raise help constraint relief'" is an economically meaningful market.[75] They assert that the Market Monitor's methodology is not consistent with either the Department of Justice or Federal Trade Commission Horizontal Merger Guidelines or the Commission's standards for identifying relevant products or geographic markets. They state that no generator submits an offer for Lanesville "raise help constraint relief" and that there are no contracts providing it either. They state that though there is a congestion component to the price that a generator receives, it is a small component of the price and is based on a weighted average of all the binding transmission constraints in PJM, not only Lanesville. Therefore, they assert that the Market Monitor's HHI calculations for Lanesville do not

[70] Applicants' December Answer at 2.

[71] Applicants' December Answer, Morris Affidavit at 3.

[72] *Id.* at 6 (stating that the facility was scheduled to be upgraded to increase its rating from 308 megavolt amperes (MVA) to 560 MVA by June 1, 2013).

[73] *Id.*

[74] *Id.*

[75] *Id.*

correspond to any meaningful market and provide no information about the competitive effects of the Proposed Transaction.[76]

56. Applicants also state that the Market Monitor confirms their analysis of the capacity market. They state that the only market with an increase in HHI in the Market Monitor report is the entire PJM Market and that the post-transaction increase in that market is well below the thresholds identified by the Commission in the Merger Policy Statement.[77] Applicants also dispute the validity of the three pivotal supplier analysis for the RPM Capacity Market. They state that the measure has several flaws such as: (1) it is calculated only for incremental supplies and therefore does not measure incentives;[78] (2) it does not consider firm size and therefore creates the potential for false positives;[79] and (3) it has no established standards for determining when there is a competitive concern and therefore is impossible to apply.[80] Applicants also believe that both HHI and the three pivotal supplier test overstate the potential competitive effects of the Proposed Transaction because of the market mitigation rules in effect for the PJM RPM auctions and the requirement of cost-based offers for most generation owners, which reduces the role of competition among suppliers in the RPM Capacity Market.[81]

57. Additionally, Applicants state that the results of the Market Monitor's analysis are consistent with the Application with respect to ancillary services, including the Regulation Market.[82] Applicants state that the Market Monitor report shows that the post-transaction HHI and increase in HHI are below the Commission's screening thresholds and that those values are based on the services provided, which overstates the concentration of the Regulation Market. Applicants assert that the Market Monitor report's use of actual regulation service provided understates the market because the

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[76] *Id.* at 7.

[77] Applicants' December Answer at 2.

[78] Applicants' December Answer, Morris Affidavit at 8.

[79] *See id.* at 8-9 (explaining that the three pivotal supplier analysis can indicate that a market has competition issues even if the transaction would be below the Commission's screening thresholds).

[80] *See id.* at 9.

[81] *Id.*

[82] *See id.* at 9-10; Applicants' December Answer at 3.

amount of regulation services offered into the market are an average of 3.61 times the amount purchased in 2012.[83] They also state that in only 20 percent of the hours studied by the Market Monitor is there an HHI change above 50 points, which they assert indicates that the HHI change on an hourly basis is typically below the Commission's screening levels.[84] Finally, Applicants assert that "[t]o guard against market power, market participants make cost-based offers and have the option of making price-based offers that are capped at $100/MWh. . . . [And] entry is easy in the [R]egulation [M]arket, which also alleviates potential competitive concern."[85]

58. Therefore, Applicants state that the Commission should not impose the behavior mitigation suggested by the Market Monitor.[86] They explain that they are subject to extensive market power monitoring and mitigation by regional transmission organizations and independent system operators, including PJM. They assert that this mitigation means that they have no choice but to engage in competitive offer behavior in the PJM market, both before and after the Proposed Transaction. They state there is nothing in the Proposed Transaction that will undermine PJM's market monitoring and mitigation regime or otherwise enable the Applicants or their subsidiaries to engage in anti-competitive offer behavior.

e. Comment on Applicants' Response to the Deficiency Letter

59. The Market Monitor argues that the most significant issue raised by the Proposed Transaction is the increase in market power in the PJM Regulation Market and the dominant position created in the Lanesville market.[87] The Market Monitor recommends that, if the Commission authorizes the Proposed Transaction, it require the merged company to make cost-based offers in the Regulation Market, and require the Market Monitor to report after 12 months on any changes in behavior in the Lanesville energy market.[88] The Market Monitor also recommends that the merged company be required to

[83] Applicants' December Answer, Morris Affidavit at 10.

[84] *Id.* at 11.

[85] *Id.* at 11-12.

[86] Applicants' December Answer at 3.

[87] *See* January 2, 2014 Comments of the Independent Market Monitor for PJM (Market Monitor's January Comment) at 1-2.

[88] *Id.* at 3.

continue to offer the same units and quantities historically offered into these markets because participation is voluntary and one way to exercise market power is simply not to offer.[89]

60. The Market Monitor provides a revised assessment of the impact of the Proposed Transaction on the PJM wholesale electricity markets including the Energy Market, the RPM Capacity Market, and the Regulation Market. The Market Monitor states that its updated report incorporates the most current available information on asset ownership, including exclusion from the entire analysis of units that retired in 2013. The revised report provides analysis using the current (as of December 2013), rather than historical, ownership and operational status of the relevant market resources in the periods. The Market Monitor states that it removed resources that retired as of December 2013 from the market structure calculations for all relevant market intervals and added units which withdrew their retirement plans.[90]

61. With respect to the Energy Market, the Market Monitor again performed a three pivotal supplier analysis of the market for the Lanesville constraint, as this is the only constraint for which both NRG and Mission Energy have significant "raise help constraint relief" capability. The Market Monitor states that though Lanesville is located in the MISO system it is located in close electrical proximity to a Commonwealth Edison (ComEd) generating station in PJM and it is one of the controlling elements identified in the PJM and MISO market to market operating agreement for which PJM can be required to provide relief. The Market Monitor focuses its results on the ability of a supplier to exercise market power in the PJM energy market, specifically in the market created by the Lanesville constraint.[91]

62. The Market Monitor found that, pre-transaction, NRG or Edison Mission supplied energy to provide "raise help constraint relief" for the Lanesville market in 229 peak hours and 54 off-peak hours. It states that NRG failed the three pivotal supplier test in 11 peak and one off-peak hours, while Edison Mission failed in 228 peak and 54 off-peak hours. The Market Monitor discovered that the Proposed Transaction would have no impact on the number of hours that the Lanesville market for "raise help constraint relief" would fail the three pivotal supplier test.[92]

[89] *Id.*

[90] Market Monitor's January Comment, Attachment at 1.

[91] *Id.* at 14-15.

[92] *Id.* at 16.

63. The Market Monitor also performed an HHI analysis on the Lanesville market. It found that the Proposed Transaction increased the HHI for the average peak market hour by 66 points from 7,554 to 7,620; it found a seven point change for the average off-peak HHI, from 9,028 to 9,034; and it found that the HHI for all hours changed by 55 points, from 7,836 to 7,890. The Market Monitor further found that, of the 277 pre-merger Lanesville market event hours with an HHI of 4,000 or more, the Proposed Transaction would cause 11 of these market event hours to have an increase of 200 or more points and 10 of these market event hours to have an increase of 300 or more points.[93]

64. The Market Monitor reasons that the three pivotal supplier results, in combination with the HHI results, indicate that Edison Mission holds a dominant position in the heavily concentrated Lanesville market and that the Proposed Transaction would, in a small subset of hours, significantly exacerbate this dominant position, increasing the combined company's incentive and ability to exercise market power in this local market. Therefore, NRG would have the ability and incentive to exercise market power in an additional local market compared to the markets in which NRG holds a dominant pre-merger position.[94]

65. With respect to the RPM Capacity Market, the Market Monitor's Total Market Analysis again showed that there was a change in the HHI for the PJM Market only; not in any submarkets. For 2015/2016 and 2016/2017, the changes in the HHI were 31 and 28 points, respectively, in an unconcentrated market.[95]

66. In its Incremental Market Analysis for capacity in PJM, the Market Monitor found three pivotal supplier test scores for all identified markets to be less than 1.00, both pre- and post-merger, indicating failure of the test. The test results showed that the Proposed Transaction resulted in changes in the test scores for only the entire PJM Market. For 2015/2016, the test score fell from 0.546 to 0.529; a decrease of 2.9 percent. For 2016/2017, the score fell from 0.597 to 0.577; a decrease of 3.5 percent. The Market Monitor argues that the Proposed Transaction would reduce three-pivotal-supplier scores, exacerbating the structural market power issues and increasing the ability of the post-merger company to exercise market power in the PJM Market, although these effects are not large.[96]

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[93] *Id.* at 17.

[94] *Id.*

[95] *Id.* at 23.

[96] *Id.* at 23-24.

67. The Market Monitor reiterates that the Regulation Market affected by NRG and Edison Mission resources is highly concentrated. The Market Monitor found that, in pre-merger terms, 53.1 percent of the market hours affected by Applicants' resources had an HHI of 1,800 or more, 37.6 percent of the market hours had an HHI of 2,000 or more, and 12.9 percent of the market hours had an HHI of 2,500 or more. The Market Monitor found that post-merger, 55.6 percent of these market hours would have had an HHI of 1,800 or more, 38.9 percent of the market hours would have had an HHI of 2,000 or more, and 13.3 percent would have an HHI of 2,500 or more. Further, the Proposed Transaction would have caused the HHI to increase by 50 or more points in 189 of the 2,280 market hours whose pre-transaction HHI was 2,000 or more. Of these 189 hours, 61 displayed an HHI increase of 100 or more points, 12 had an increase of 200 or more points, and one had an increase of 300 or more points.[97]

68. On January 6, 2014, the Market Monitor submitted non-substantive corrections to the Market Monitor January Comment. It states that it provided the corrections to ensure clarity and consistency.[98]

f. Applicants' January Answer

69. Applicants state that the Market Monitor's January comments are simply an untimely rehashing of its earlier comments, which they state they have already addressed.[99] They assert that the Market Monitor's revised analysis again largely confirms the Application and that it fails to justify the Market Monitor's requests for market power mitigation. Furthermore, Applicants state that none of the issues raised by the Market Monitor justify denying, delaying or conditioning authorization of the Proposed Transaction. Applicants reiterate that, with respect to regulation service, the Market Monitor erred in only considering cleared regulation offers.[100] Finally, Applicants again criticize the Market Monitor's use of data that does not consider the effects of the transmission upgrades at Lanesville, which they assert fully alleviated the constraint.[101]

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[97] *Id.* at 25.

[98] January 6, 2014 Corrections of the Independent Market Monitor for PJM at 1.

[99] Applicants' January Answer at 2.

[100] *Id.* at 2-3.

[101] *Id.* at 3.

g. Market Monitor's Answer

70. The Market Monitor admits that Applicants are correct that the upgrade affecting the Lanesville constraint appears to have eliminated the Lanesville market for constraint relief, based on results for June 1, 2013 through December 31, 2013.[102] The Market Monitor argues, though, that the analysis it performed on the Lanesville market has the advantage of providing analysis based on actual system conditions, which allows a study of market structure based on PJM's actual security constrained, economic dispatch. It states that the analysis of actual market conditions, regardless of the details, cannot be a forecast and there is limited information on which to base forecasts of system changes which would change the security constrained economic dispatch solution. In this case, the Market Monitor's analysis of actual market conditions shows that a relief market that is dependent on resources in the ComEd zone, under specific system conditions, is highly concentrated and the Proposed Transaction would exacerbate this concentration. The Market Monitor states that while the issue of the Lanesville constraint appears to have been resolved, the increased concentration of resources that would result from the Proposed Transaction remains a concern in any "raise help constraint relief" market that develops in the area going forward.[103]

71. The Market Monitor identifies one additional market in that has appeared since MISO upgraded Lanesville: the Byron – Cherry Valley "raise help constraint relief" market, which did not occur during the 2012-2013 planning period, but which did occur in the ComEd zone following the upgrades. It states that the Byron – Cherry Valley "raise help constraint relief" market occurred in 67 hours in the June 1, 2013 through December 30, 2013 study period and the PJM and MISO market to market operating agreement identifies the constraint as a controlling element which can be required to provide relief. The Market Monitor explains that the Byron – Cherry Valley constraint has significant overlap with the resources in the pre-upgrade Lanesville "raise help constraint relief" supply curve and is similarly concentrated.[104]

72. The Market Monitor found that in the 67 hours that Edison Mission or NRG provided "raise help constraint relief" supply for the Byron – Cherry Valley constraint all of these hours had pre-merger HHIs of 2,500 or more, and 66 of these market hours (98.5 percent of relevant market hours) had a pre-merger HHI of 4,000 or more. It states

[102] Answer of the Independent Market Monitor for PJM (Market Monitor's Answer), Attachment at 2.

[103] *Id.* at 2.

[104] *Id.*

that of the 66 pre-transaction Byron – Cherry Valley market event hours with an HHI of 4,000 or more, the Proposed Transaction would cause 33 of these market event hours to have an increase of 200 or more points and 30 of these market event hours to have an increase of 300 or more points. It explains that these are the market hours where both NRG and Mission Energy concurrently provided "raise help constraint relief" supply for the Byron – Cherry Valley constraint after the Lanesville upgrades.[105]

73. The Market Monitor states that it remains concerned that the Proposed Transaction would have a significant impact on a relief market that is dependent on resources in the ComEd zone. The Market Monitor does not believe that the conditions require specific mitigation with respect to markets for "raise help constraint relief" as a condition of the Proposed Transaction at this time, but requests that the Commission, as a condition of approving the merger, direct it to monitor and report after 12 months on the merged companies' behavior and performance in the ComEd zone.[106]

74. The Market Monitor disagrees with Applicants' assertion that market shares, and the resulting calculations of HHI, should be based on total offers, regardless of price, rather than what actually clears in the market. It also disagrees with Applicants' assessment that it is unlikely that any one market participant would find it profitable to withhold services because of the excess offers of regulation services.[107] The Market Monitor also argues that NRG has provided no evidence that market concentration in the Regulation Market is not a concern because entry is easy in the Regulation Market.[108] The Market Monitor also disagrees with Applicants' assertion that its Regulation Market HHI analysis confirms Applicants' conclusion that there is no need for mitigation due to the Proposed Transaction.[109]

75. The Market Monitor states that a firm's market share is the percentage of a market served by that firm and that central to this definition is the concept that the market share is the portion of demand actually served by the firm, not the portion of total supply under the control of the firm in question, regardless of cost. The Market Monitor therefore argues that a Regulation Market share is the percentage of the market actually served by a

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[105] *See id.* at 3.

[106] *Id.*

[107] *Id.* at 4.

[108] *Id.* at 6.

[109] *Id.* at 4.

supplier and not the proportion of total regulation capability offered, regardless of price. It asserts that a firm's proportion of demand served by that firm is the basis for a firm's actual market share.[110]

76. The Market Monitor states that regulation offers stand for 24 hours at a time, yet regulation resources are not eligible to clear in every hour. It states that PJM only considers a regulation offer if the resource is available to provide regulation, which typically means the resource must be on line and it must have flagged its standing offer as available. The Market Monitor asserts that, even if the resource is eligible to provide regulation, the optimization engine may not clear it because its total offer (lost opportunity cost plus offer) is uneconomic, and therefore not competitive. Therefore, the Market Monitor asserts that the resource may not be a relevant source of competition and it concludes that an analysis that ignores the relative competiveness of offers will incorrectly treat high-priced offers as competitors in a low-price market.[111]

77. The Market Monitor defends its analysis by stating that proper analysis of market structure must identify and evaluate proper substitutes for a given product and should use available data. It asserts that proper data and definitions take into account the substitutability or lack thereof among supply options and identify the relative importance of merging firms.[112] The Market Monitor states that it based its definition of the relevant market on "the actual substitutability and relative competitiveness among available, relevant regulation resources, which in turn is based on the offers or failure to offer, the offer prices and the physical facts of the system."[113] It asserts that these factors determine how PJM markets define the substitutability among available regulation resources in the relevant Regulation Market over the analysis period. The Market Monitor reiterates that it analyzed the Regulation Market as defined by the actual operation of the market, based on regulation MW actually cleared, which therefore reflects the information available based on the actual operation of the PJM Regulation Markets, rather than approximations that ignore relative dispatch costs.[114]

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[110] *Id.*

[111] *See id.*

[112] *Id.* at 5.

[113] *Id.*

[114] *Id.*

78. The Market Monitor disagrees with Applicants' assertion that mitigation is unnecessary in the Regulation Market. It states that while current market rules can mitigate regulation offers, there is no obligation to offer or make available a resource's regulation capability in the PJM system. It asserts that the current market rules, therefore, make it possible to withhold capacity from the Regulation Market, which can affect Regulation Market prices in a way that is not possible with offers that are subject to market power mitigation.[115] The Market Monitor argues that the issues it identified require mitigation. It recommends that, if the Commission authorizes the Proposed Transaction, the Commission should require NRG to make cost-based offers in the Regulation Market and be required to continue to offer the same units and quantities historically offered into the Regulation Market because participation is voluntary and one way to exercise market power is simply not to offer. The Market Monitor also recommends that the Commission require NRG to make cost-based offers in the Regulation Market and that the Commission direct the Market Monitor to monitor and report after 12 months on the behavior and performance of NRG in the ComEd zone.[116]

h. <u>Commission Determination</u>

79. Based on the facts as presented in the Application, we find that the Proposed Transaction will not have an adverse effect on horizontal competition. Applicants' analysis demonstrates that the Proposed Transaction does not fail any of the Commission's screens for horizontal market power. Further, as discussed below, we find that the Market Monitor has not shown that the Proposed Transaction will have an adverse impact on horizontal market power.

80. We will not consider the market for "raise help constraint relief" for either Lanesville or Byron – Cherry Valley as a separate relevant submarket at this time. First, we note that the upgrades to the Lanesville facility have eliminated it as a possible binding constraint, as noted by Applicants and conceded by the Market Monitor. Second, the evidence of a limited number of binding hours at Byron – Cherry Valley provided by the Market Monitor does not show that the constraint is a frequently binding transmission constraint that creates prices 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 within the proposed alternative geographic

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[115] Market Monitor's Answer, Attachment A at 6.

[116] *Id.* at 5-7.

market.[117] This demonstration could be made by providing evidence of binding transmission constraints or price separation data.[118] However, the Market Monitor has not made such a demonstration. Therefore, we will not condition the Proposed Transaction by directing the Market Monitor to monitor and report after 12 months on the behavior and performance of NRG in the ComEd zone. Nevertheless, we remind parties that the Market Monitor has the authority to monitor and report on any market participant's behavior and performance in any market which it has the authority to monitor.

81. We find the Proposed Transaction will not adversely affect horizontal competition in the RPM Capacity Market. Though the three pivotal supplier test is not part of the Commission's analysis under the *Merger Policy Statement*, we consider alternative measures when intervenors make a convincing case.[119] Here the Market Monitor fails to do so because its analysis of the Proposed Transaction only shows a small increase in market concentration in the RPM Capacity Market. The Market Monitor's three pivotal supplier test scores only shows a change of 0.9 percent for the 2015/2016 period and a change of 3.1 percent for the 2016/2017 period.[120] Furthermore, the Market Monitor calculated changes in HHI of 31 and 28 for 2015/2016 and 2016/2017 for the RPM Capacity Market. The RPM Capacity Market has explicit market power mitigation rules designed to limit the exercise of market power via the application of the three pivotal supplier test and offer capping. These rules, the absence of any screen failures under our Appendix A analysis, and the fact that the Market Monitor has not made a convincing case that the Proposed Transaction has anticompetitive effects mitigate our concerns about the exercise of market power in the RPM Capacity Market.

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[117] *Exelon Corp.*, 138 FERC ¶ 61,167, at P 32 & n.29 (2012). *See also Dominion Energy Brayton Point, LLC*, 144 FERC ¶ 61,139, at P 37 (2013); *Central Vermont Pub. Serv. Corp.*, 138 FERC ¶ 61,161, at P 29 (2012); *FirstEnergy Corp.*, 133 FERC ¶ 61,222, at P 52 (2010); *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)); *Boralex Livermore Falls LP*, 122 FERC ¶ 61,033, *order on reh'g*, 123 FERC 61,279, at P 25 (2008).

[118] *Exelon Corp.*, 138 FERC ¶ 61,167 at P 32 (citing *First Energy Corp.*, 133 FERC ¶ 61,222 at P 52).

[119] *See* Order No. 642, FERC Stats. & Regs. ¶ 31,111 at 31,897.

[120] Market Monitor's December Comment, Attachment A at 22.

82. Finally, we also find that the Proposed Transaction will not adversely affect competition in the Regulation Market. The Commission is normally concerned with cases where there are systematic screen failures, that is, where screen failures "present a consistent pattern across time periods and/or markets."[121] Because the Market Monitor's conservative analysis presents only isolated screen failures in 189 hours of the year studied (or 2.16 percent), and many of these hours are non-contiguous and are spread over many time periods, we find there are no competitive concerns raised by the Market Monitor's analysis of the Proposed Transaction's effect on the Regulation Market. Furthermore, Applicants' analysis demonstrates that the Proposed Transaction satisfies the Commission's screens (because the HHI change is less than 100 in a moderately concentrated market) and therefore does not adversely affect horizontal competition in the Regulation Market. Therefore, we will not condition the Proposed Transaction on the Market Monitor's suggested behavioral mitigation.

2. Effect on Vertical Competition

a. Applicants' Analysis

83. Applicants argue that the Proposed Transaction raises no concerns with respect to vertical market power. Applicants state that neither they nor any affiliate owns or controls any operational transmission facilities, other than limited transmission facilities necessary to interconnect generating facilities to the transmission grid, and the Proposed Transaction does not involve any transmission facilities, other than those limited facilities necessary to interconnect generating facilities to the grid. Furthermore, Applicants state that neither they nor any affiliate owns or controls inputs to electricity products that could be used to erect barriers to entry, and the Proposed Transaction does not involve inputs to electricity products, other than sites for generation capacity development controlled by certain of Edison Mission's subsidiaries. Accordingly, Applicants maintain that the Proposed Transaction presents no vertical market power concerns, and no vertical market power analysis is required.[122]

b. Commission Determination

84. Based on the facts as presented in the Application, we find that the Proposed Transaction does not raise vertical market power concerns because it does not involve the transfer of any transmission facilities other than limited and discrete interconnection

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[121] *See, e.g.*, *Florida Power & Light Co.*, 145 FERC ¶ 61,018, at P 45, n.59 (2013); *Bluegrass Generation Company, L.L.C.*, 139 FERC ¶ 61,094, at P 28 (2012).

[122] Application at 53.

facilities. The Proposed Transaction also creates no new vertical combinations of assets. Thus, there will be no increased incentive or ability to harm competition. Moreover, we note that no party has raised concerns about vertical competition.

3. Effect on Rates

a. Applicants' Analysis

85. Applicants argue that the Proposed Transaction will not adversely affect rates. Applicants state that the Edison Mission Public Utilities will continue to make wholesale sales of electric energy, capacity, and ancillary services at market-based rates or pursuant to the terms of other rate schedules on file with the Commission, and that the Proposed Transaction will have no effect on the rates for such sales. Moreover, Applicants state that none of Applicants or their affiliates is a traditional utility with captive retail or wholesale customers or provides unbundled transmission service. They state that the only cost-based rate schedule involved in the Proposed Transaction is the rate schedule establishing Midwest Generation's revenue requirement for reactive power compensation pursuant to Schedule 2 to the PJM Tariff. They assert that nothing in this rate schedule, Schedule 2 to the PJM Tariff, or any of the rate schedules or tariffs under which NRG Holdings' affiliates receive cost-based compensation for reactive power, black start service and reliability must-run service would allow for the pass-through of costs associated with the Proposed Transaction. Accordingly, they state that the Proposed Transaction will not have an adverse effect on rates to wholesale customers served under these cost-based rate schedules.[123]

b. Commission Determination

86. Based on Applicants' representations, we find that the Proposed Transaction will not adversely affect wholesale requirements or transmission rates. We emphasize at the outset that our analysis of rate effects under section 203 of the FPA differs from the analysis of whether rates are just and reasonable under section 205 of the FPA. Our focus here is on the effect that the Proposed Transaction will have on jurisdictional rates, whether that effect is adverse, and whether any adverse effect will be offset or mitigated by benefits that are likely to result from the Proposed Transaction.[124]

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[123] *Id.* at 53-54.

[124] *See, e.g.*, *Merger Policy Statement*, FERC Stats. & Regs. ¶ 31,044, at 30,123 (noting that an increase in rates "can be consistent with the public interest if there are countervailing benefits that derive from the transaction"); *see also ITC Midwest LLC*, 133 FERC ¶ 61,169, at P 24 (2010); *ALLETE, Inc.*, 129 FERC ¶ 61,174, at P 19 (2009);

(continued…)

87. With regard to wholesale rates, Applicants will continue to make wholesale sales of electric energy, capacity and ancillary services at market-based rates or cost-based rates. Applicants state that under the terms of their and NRG Holdings' affiliates cost-based rates, they will have no ability to pass through any increased costs resulting from the Proposed Transaction. Based on Applicants' representations, we find that the Proposed Transaction will not adversely impact wholesale customers' rates for energy, capacity, and ancillary services.

88. With regard to the effect of the Proposed Transaction on transmission rates, we note that there are no transmission customers whose rates could be adversely impacted by the Proposed Transaction. We also note that no party argued that the Proposed Transaction would have an adverse effect on rates.

4. Effect on Regulation

a. Applicants' Analysis

89. Applicants maintain that the Proposed Transaction will not have any adverse effect on the effectiveness of federal or state regulation, as Applicants' regulatory status will remain unchanged and will not create any gaps in regulation. Similarly, the Applicants state that the Proposed Transaction will not affect the extent to which any state authority can regulate retail rates.[125]

b. Commission Determination

90. 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.[126] Based on Applicants' representations, we find that neither state nor federal regulation will be impaired by the Proposed Transaction. Specifically, 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 Applicants after consummation of the Proposed Transaction.

Startrans IO, L.L.C., 122 FERC ¶ 61,307, at PP 25-28 (2008); *ITC Holdings Corp.*, 121 FERC ¶ 61,229, at PP 120-128 (2007).

[125] Application at 54.

[126] *Merger Policy Statement*, FERC Stats. & Regs. ¶ 31,044, at 30,124.

91. In the Merger Policy Statement, the Commission stated that it ordinarily will not set the issue of the effect of a transaction on the state regulatory 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.[127] We note that no party alleges that 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.

5. Cross-Subsidization

a. Applicants' Analysis

92. Applicants assert that the Proposed Transaction falls squarely within the safe harbor for transactions that do not involve a franchised public utility with captive customers. Furthermore, Applicants maintain that the Transaction is a *bona fide*, arm's length, bargained-for exchange between non-affiliated entities. Applicants state that under such circumstances, the Commission has recognized that there is no potential for harm to customers.[128] Nevertheless, Applicants verify that, based on facts and circumstances known to them or that are reasonably foreseeable, the Proposed Transaction will not result in, at the time of the Proposed Transaction or in the future, cross-subsidization of a non-utility associate company or the pledge or encumbrance of utility assets of a traditional public utility associate company that has captive customers or that owns or provides transmission service over jurisdictional facilities for the benefit of an associate company, including: (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 contracts 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

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[127] *Id.*

[128] Application at 55 (citing *Supplemental Policy Statement*, FERC Stats. & Regs. ¶ 31,253 at P 17 (cross-referenced at 120 FERC ¶ 61,060 at P 17)).

jurisdictional transmission facilities, other than non-power goods and service agreements subject to review under sections 205 and 206 of the FPA.[129]

b. Commission Determination

93. Based on the facts as presented in the Application, we find 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 note that no party has argued otherwise.

6. Other Issues

94. Order No. 652 requires that sellers with market-based rate authority timely report to the Commission any change in status that would reflect a departure from the characteristics the Commission relied upon in granting market-based rate authority.[130] To the extent that the foregoing authorization results in a change in status, Applicants are advised that they must comply with the requirements of Order No. 652. In addition, Applicants shall make any appropriate filings under section 205 of the FPA to implement the Proposed Transaction.

95. Information and/or systems connected to the bulk power system involved in the Proposed 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.

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[129] Application, Exhibit M at 1-2.

[130] *Reporting Requirements for Changes in Status for Public Utilities with Market-Based Rate Authority*, Order No. 652, FERC Stats. & Regs. ¶ 31,175, *order on reh'g*, 111 FERC ¶ 61,413 (2005). *See* 18 C.F.R. § 35.42 (2013).

<u>The Commission orders</u>:

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

(B) Applicants must inform the Commission within 30 days of any material change in circumstances that departs from the facts the Commission relied upon in granting the Application.

(C) 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 costs, or any other matter whatsoever now pending or which may come before the Commission.

(D) 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.

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

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

(G) Applicants shall account for the Proposed Transaction in accordance with Electric Plant Instruction No. 5 and Account 102, Electric Plant Purchased or Sold, of the Uniform System of Accounts. Applicants shall submit their final accounting entries within six months of the date that the Proposed Transaction is consummated, and the accounting submissions shall provide all the accounting entries and amounts related to the Proposed Transaction along with narrative explanations describing the basis of the entries.

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

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.