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VIA ELECTRONIC FILING

January 6, 2014

Kimberly D. Bose, Secretary
Nathaniel J. Davis, Sr., Deputy Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

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

Dear Secretary Bose:

Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor for PJM ("Market Monitor"), here submits corrections to the filing by the Market Monitor of comments and an attached report in the above referenced proceeding on January 2, 2014. The corrections are non substantive, and are provided to ensure clarity and to ensure consistency between the comments and the attached report. A clean version of the corrected comments and attached report is included as Attachment A, and a redline version of pages with revisions (only) is included as Attachment B.

The Market Monitor respectfully requests that the Commission include these corrections in the record for this proceeding.

Sincerely,

Jeffrey W. Mayes, General Counsel

Attachment A

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

COMMENTS OF
THE INDEPENDENT MARKET MONITOR FOR PJM

Pursuant to Rule 211 of the Commission's Rules and Regulations,[1] Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor for PJM ("Market Monitor"),[2] submits these comments on the joint application of NRG Energy Holdings Inc. ("NRG") and Edison Mission Energy ("EME") for approval of a transaction whereby NRG would acquire substantially all of the assets of EME, as amended by applicants response dated December 16, 2013, to the Commission notice of deficiency issued December 5, 2013. In its pleading dated December 9, 2013, the Market Monitor provided an alternative analysis and comments in a report ('December 9th Report"). The Market Monitor attaches to this pleading, as an Attachment, an updated report ("January 2nd Report"), which, among other things, conforms some of the analysis to be consistent with the information requested by the Commission in its December 5th notice.

The most significant issues identified in both the December 9th Report and the January 2nd Report relevant to the standards of review applicable to a merger under Section 203 of the Federal Power Act are: the increase in market power in the PJM Regulation Market that will result from combining the assets of the two companies; and the dominant

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1 18 CFR § 385.211 (2011).

2 Capitalized terms used herein (including the attached report) and not otherwise defined have the meaning used in the PJM Open Access Transmission Tariff ("OATT").

position in a specific local energy market that NRG would gain as a result of the merger. The Market Monitor believes that these issues can be addressed by conditioning approval of the merger on the applicants' adoption of mitigation in the form of behavioral rules applicable to applicants' participation in the PJM Regulation Market and a requirement that the Market Monitor report to the Commission after 12 months on any changes in behavior in the identified local energy market.

I. COMMENTS

A. Updated Report.

The Market Monitor's January 2nd Report provides an assessment of the impact of the proposed merger between NRG and EME on PJM wholesale electricity markets including the Energy Market, the Capacity Market and the Regulation Market. In conducting this analysis the Market Monitor has made use of actual dispatch, offer and availability data to define the relevant markets and to examine the effects of the proposed merger on those markets using concentration ratios and pivotal supplier indices. The Commission has accepted and considered similar analyses when evaluating proposed mergers in PJM.[3]

The analysis presented in this report covers the impact of the proposed merger on the structure of the PJM markets, using current data. The analysis examines market structure metrics in order to quantify the expected impact of the proposed merger on the market structure of constraint defined markets within PJM. The analysis concludes that the proposed merger would significantly increase concentration in a specific, highly concentrated locational energy market, would increase concentration and reduce TPS scores

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[3] *See* 138 FERC ¶ 61,167; *see also Analysis of Horizontal Market Power under the Federal Power Act*, 138 FERC ¶ 61,109 (2012) ("We reiterate, however, that the Commission may consider arguments that a proposed transaction raises competitive concerns that have not been captured by the Competitive Analysis Screen. Likewise, while applicants must continue to provide a Competitive Analysis Screen, we will also consider any alternative methods or factors, if adequately supported.").

in the capacity market although the effect is not large and would significantly increase concentration in the market for regulation.

B. Behavioral Mitigation Is Needed to Address Market Power Issues in the PJM Regulation Market and in a Specific Locational Energy Market.

In both the December 9th Report and the January 2nd Report, the Market Monitor identified an increase in concentration levels in the PJM Regulation Market that would result from combining the assets of NRG and EME. This means that the proposed merger would significantly increase concentration in a specific, highly concentrated locational energy market, would increase concentration and reduce TPS scores in the capacity market although the effect is not large, and would significantly increase concentration in the market for regulation. In its December 9th Report, the Market Monitor recommended that the Commission consider behavioral mitigation, in the form of requirements to engage in competitive offer behavior in each PJM market, to resolve the issues identified.

The proposed merger would have a limited impact on the overall competitiveness of PJM markets, but would have a significant impact on one local energy market and a significant impact on the regulation market. The IMM recommends that the Commission require behavioral mitigation measures to address the issues identified in this report. Appropriate mitigation could resolve the identified concerns about competitive impacts. The IMM recommends that, if the merger is approved, the Commission require the merged company to make cost-based offers in the regulation market and that the Commission require the IMM to report after 12 months on any changes in behavior in the identified local energy market. The Market Monitor also recommends that the merged company 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 proposed conditions are proportionally limited in scope and scale to the issues identified in the Market Monitor's analysis. The substance of this condition merely requires that the applicants behave competitively in the PJM Regulation Market, consistent with fundamental Commission regulatory policy. Accordingly, a requirement that the applicants adhere to the proposed behavioral requirements should be made a condition for any approval of the application for merger.

II. CONCLUSION

The Market Monitor respectfully requests that the Commission afford due consideration to these comments as the Commission resolves the issues raised in this proceeding.

Respectfully submitted,

Jeffrey W. Mayes

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Dated: January 2, 2014

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Eagleville, Pennsylvania,
this 2nd day of January, 2014.

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Attachment

Review and Analysis of the Proposed Merger of NRG and Edison Mission Energy

The Independent Market Monitor for PJM

January 2, 2014

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Table of Contents

Introduction

This report was prepared by PJM's Independent Market Monitor (IMM). The report provides a revised assessment of the impact of the proposed merger between NRG and Edison Mission Energy on PJM wholesale electricity markets including the Energy Market, the Capacity Market and the Regulation Market. In conducting this analysis the PJM IMM made use of actual dispatch, offer and availability data to define the relevant markets and to examine the effects of the proposed merger on those markets using concentration ratios and pivotal supplier indices.

This report incorporates the most current available information on asset ownership, including exclusion from the entire analysis of units that retired in 2013. The prior report provided analysis of the energy market based on ownership and available resources at the time the market interval was cleared in the 2012-2013 planning year; of the regulation market based on ownership and available resources at the time the market interval was cleared in the October 2012 through September 2013[1]; and of the capacity market based on current ownership and withdrawn deactivation requests at the time of the analysis. This revised report provides the analysis for the same periods using the current (as of December 2013), rather than historical, ownership and operational status of the relevant market resources in the periods. Resources that retired as of December 2013 have been removed from the market structure calculations for all relevant market intervals and units for which retirement plans have been withdrawn have been added. Any changes in the ownership of market resources have been fixed at December 2013 for all the relevant market intervals studied. The list of units attributed to NRG appears in Appendix A. The list of units attributed to Edison Mission Energy appears in Appendix B.

Summary

The analysis presented in this report covers the impact of the proposed merger on the structure of the PJM markets, using current data. The analysis examines market structure metrics in order to quantify the expected impact of the proposed merger on the market structure of constraint defined markets within PJM. The analysis concludes that the proposed merger would significantly increase concentration in a specific, highly concentrated locational energy market, would increase concentration and reduce TPS scores in the capacity market although the effect is not large and would significantly increase concentration in the market for regulation.

[1] The design of the Regulation Market changed significantly effective October 1, 2012. The analysis of the regulation market is based on the market structure as it exists after this change.

The proposed merger would have a limited impact on the overall competitiveness of PJM markets, but would have a significant impact on one local energy market and a significant impact on the regulation market. The IMM recommends that the Commission require behavioral mitigation measures to address the issues identified in this report. Appropriate mitigation could resolve the identified concerns about competitive impacts. The IMM recommends that, if the merger is approved, the Commission require the merged company to make cost-based offers in the regulation market and that the Commission require the IMM to report after 12 months on any changes in behavior in the identified local energy market. The Market Monitor also recommends that the merged company 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.

Methods of Analysis

In analyzing whether a proposed merger is consistent with the public interest, the FERC considers the "effect of the transaction on competition, rates, and regulation of the applicant by the Commission and state commissions with jurisdiction over any party to the transaction."[2] In this report, the IMM focuses on the first factor, the effect on competition, measured by the impact on the structure of relevant markets based on actual market data. The IMM evaluates the impact of the merger using concentration thresholds, including those defined in FERC's Competitive Analysis Screen,[3] and pivotal supplier analysis.

Any analysis of market structure depends on an accurate definition of the relevant markets. Market definitions depend on properly identifying and evaluating potential substitutes for a given product. Within organized markets data are available, and should be used, to define markets based on how the units are evaluated and dispatched to meet demand, based on networked relationships between resources and load, relative costs, availability and operational parameters. Such an approach provides definitions of the

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2 18 CFR § 33.2(g) (2011).

3 18 CFR § 33.3; *see also Revised Filing Requirements Under Part 33 of the Commission's Regulations*, Order No. 642, FERC Stats. & Regs. ¶ 31,111 (2000) ("Order No. 642"); *Transactions Subject to FPA Section 203*, Order No. 669, FERC Stats. & Regs. ¶ 31,200 (2005) ("Order No. 669"), *order on reh'g*, Order No. 669-A, FERC Stats. & Regs. ¶ 31,214 ("Order No. 669-A"), *order on reh'g*, Order No. 669-B, FERC Stats. & Regs. ¶31,225 (2006) ("Order No. 669-B"); *Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement*, Order No. 592, 77 FERC ¶61,263 (*mimeo*), FERC Stats. & Regs. ¶ 31,044 (1996), *reconsideration denied*, Order No. 592-A, 79 FERC ¶61,321 (1997) ("Merger Policy Statement"); *FPA Section 203 Supplemental Policy Statement*, FERC Stats. & Regs. ¶ 31,253 (2007).

relevant markets based on actual operational data related to the participants and the markets in which they operate. Evaluated in this manner, the substitutability or lack of substitutability among supply options in a market is made transparent, along with the relevant market(s), and the relative importance of the merging firms within the market(s). It is on this basis that the use of prescribed formulas regarding market shares, residual suppliers and concentration ratios, as well as other metrics, can be useful tools for evaluating the effects of a proposed merger.

In the IMM analysis, the definition of the relevant market is based on the actual substitutability among available, relevant resources which in turn is based on the physical facts of the system and how the PJM markets defined the substitutability among available resources in the relevant markets over the analysis period. Rather than limit its analysis to a predefined range of load and price levels, the IMM has analyzed every actual relevant market defined by a constraint and the system software. The relevant energy markets in this analysis are those local energy markets created by transmission constraints within the broader PJM market that occurred for one hundred or more hours in the 2012-2013 planning year. The relevant ancillary services markets are those defined by the actual operation of PJM markets over the October 1, 2012 through September 30, 2013 period. The relevant capacity markets are those that resulted from the actual operation of the markets for the 2015/2016 and 2016/2017 delivery years.

The IMM analysis of the relevant markets reflects the information available based on the actual operation of the PJM wholesale power markets, rather than approximations of seasonal geographic markets that ignore local transmission constraints, distribution factors and relative dispatch costs. The information used to prepare the analysis included in this report is highly confidential and market sensitive as it relates to specific market participants.[4]

The IMM analysis relies on what FERC terms economic capacity, or total capacity without netting of load obligations, also termed gross position. Net positions would be calculated by subtracting the load obligation from the supply of the relevant product for all participants that have both an obligation to purchase a product or to sell a product at a defined price and the ability to supply a product. Such participants, in this analysis, would be primarily integrated utility companies that have not yet been exposed to significant retail competition and that therefore retain most of their native load. A net position analysis would show the market results when the integrated utility companies retain their dominant position in the market. A complete net position analysis would also have to account for all financial positions of the respective companies which affect

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[4] See OATT Attachment M–Appendix § I.

their net positions. The gross position analysis shows the market results when the integrated utility companies either no longer have the load obligation or have separated their generation companies from the integrated company so that their financial incentives no longer correspond to those of a fully integrated company. While the net position analysis may illustrate the current incentives to increase prices based on current load obligations and other financial market obligations, another impact of higher prices that is not explicitly considered is the fact that high prices for the relevant product could serve as a barrier to entry by competitive retail suppliers who would have to pay the high price in order to compete with the incumbent utility. The gross position, or economic capacity, analysis is more appropriate to the evaluation of the long-term impacts of a merger in a market with widespread although not ubiquitous retail competition and is the approach taken here.

Merger Standards

For the evaluation of the impact of a merger on competition, FERC adopted the 1992 Horizontal Merger Guidelines as the analytical framework for analyzing the impact of mergers on competition as described in the Commission's Competitive Analysis Screen.[5]

The Commission reserves the opportunity to consider alternative approaches for analyzing the impact of proposed mergers, including analyses similar to the analysis included in this report, when evaluating proposed mergers in PJM.[6]

The 1992 Guidelines outlined the enforcement policy of the Department of Justice and the Federal Trade Commission concerning horizontal mergers subject to section 7 of the Clayton Act, section 1 of the Sherman Act, and Section 5 of the Federal Trade Commission Act. As noted in the Guidelines, "[t]he unifying theme of the Guidelines is

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5 *See* Order No. 642 *mimeo* at 4–5; U.S. Dept. of Justice & Federal Trade Commission, "Horizontal Merger Guidelines" (1992), as revised (1997) (1992 Guidelines) ("1992 Guidelines"). DOJ and FTC modified their guidelines in 2010, increasing their HHI and market share thresholds and expanding the criteria used to define the relevant market. U.S. Dept. of Justice & Federal Trade Commission, "Horizontal Merger Guidelines" (August 19, 2010). FERC considered whether to revise it policies to follow the DOJ and FTC 2010 modifications, but decided, after notice and inquiry, to retain the 1992 Guidelines. *Analysis of Horizontal Market Power under the Federal Power Act*, 138 FERC ¶61,109 (2012).

6 *See Id*. at P 38 ("We reiterate, however, that the Commission may consider arguments that a proposed transaction raises competitive concerns that have not been captured by the Competitive Analysis Screen. Likewise, while applicants must continue to provide a Competitive Analysis Screen, we will also consider any alternative methods or factors, if adequately supported."); *Exelon Corporation, Constellation Energy Group, Inc.*, 138 FERC ¶ 61,167 (2012).

that mergers should not be permitted to create or enhance market power or facilitate its exercise."[7]

FERC's Competitive Analysis Screen, based on the 1992 Guidelines, uses market concentration, measured by the HHI, as a basic metric of the structural competitiveness of a market. The 1992 Guidelines define three basic levels of market concentration while recognizing that "[o]ther things being equal, cases falling just above and just below a threshold present comparable competitive issues."[8] A market with an HHI of less than 1000 is considered to be unconcentrated. Mergers resulting in HHI level less than a 1000 are not considered to have adverse competitive effects. A market with an HHI between 1000 and 1800 is considered to be moderately concentrated. A merger in or resulting in a moderately concentrated market is not considered to have an adverse effect on competition if it increases the market's HHI by less than 100 points. A merger in or resulting in a moderately concentrated market is considered to "potentially raise significant competitive concerns" if it increases the market's HHI by 100 points or more.[9] A market with an HHI of 1800 or above is considered to be highly concentrated. A merger in or resulting in a highly concentrated market is not considered to have an adverse effect on competition if it increases the market's HHI by less than 50 points. A merger producing an increase in the market HHI of 50 points or more in a highly concentrated market "potentially raises significant competitive concerns."[10]

The 1992 Guidelines do not directly address whether changes in HHI are of greater concern at higher starting HHI, such as 4000. Presumably the higher the starting the HHI, the greater the concern caused by a given increase in HHI caused by a merger.

Both the DOJ's 1992 Guidelines and the Commission's Appendix A use their respective HHI thresholds and measures as a guideline, and the importance of a specific range is dependent on a number of other factors, such as the amount of demand response that exists in a given market. All else held equal, where a lack of potential demand response might allow prices to be raised by more than a "small but significant and non-transitory" amount, "more market power is at stake in the relevant market than in a market in which a hypothetical monopolist would raise price by exactly five percent."[11]

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[7] 1992 Guidelines at 2.

[8] 1992 Guidelines at 15.

[9] *Id*. at 16.

[10] *Id*.

[11] *Id*. *at* 17.

In making the determination with respect to post merger market power, the Commission's analytic screen focuses primarily on the market concentration analysis as detailed in the Guidelines. In both cases, the concentration analysis requires the definition of product and geographic markets that are likely to be affected by a proposed merger and the measurement of concentration in those markets. The product and geographic market definitions used in the Commission analysis are designed to identify the pool of feasible alternative suppliers to the merged firm from a buyer's perspective, taking into account the costs of delivering the product and various measures of transmission capacity between potential suppliers and potential buyers, under varying market conditions (load levels).

The Commission approach requires analysis at a range of load and price levels given the effect of the combination of load levels and seasons on the competitive price. The IMM has performed its energy market analysis on the basis of every actual relevant market interval defined by an identified constraint and the system software during the 2012-2013 planning year. The IMM has performed its capacity market analysis on the basis of the cleared LDAs in the Base Residual Auctions for 2015/2016 and 2016/2017. The IMM has performed its ancillary services market analysis on the basis of the actual hourly cleared markets for the October 2012 through September 2013 period.

Where the analysis indicates that a proposed merger may significantly increase concentration in any of the relevant markets, the FERC then examines the merger using the remaining four analytic steps from the Guidelines. This process involves an "examination of other factors that either address the potential for adverse competitive effect or that could mitigate or counterbalance the potential competitive harm."[12] FERC notes that "(s)uch factors include the ease of entry in the market or any efficiencies stemming from the merger."[13] Where such "additional factors examined do not mitigate or counterbalance the adverse competitive effects of the merger," remedial, mitigative conditions can be explored by FERC.[14] Such remedial, mitigative conditions or actions can include, but are not limited to transmission expansion and/or generation divestiture.[15]

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12 Merger Policy Statement, Appendix A at 3.

13 *Id*.

14 *Id*. at 3–4.

15 *Id*. at 23–27.

Market Based Rate Authority Metrics

The FERC's Market-Based Rates Order, Order No. 697, defines the market structure characteristics that must be met for a market participant to be granted market based rates for three years.[16] Order No. 697 indicates that an individual seller market share in excess of 20 percent is an indicator of market power and that an HHI of 2500 is an indicator of market power.[17] Order No. 697 also uses the residual supplier index (RSI), a pivotal supplier metric, to define market structure.[18]

The Commission adopted market power screens and tests in the Order No. 697.[19] The Order No. 697 defined two indicative screens and the more dispositive delivered price test. The Commission's delivered price test for market power defines the relevant market as all suppliers who offer at or below the clearing price times 1.05 and, using that definition, applies pivotal supplier, market share and market concentration analyses. These tests are failed if, in the relevant market, the supplier in question is pivotal, has a market share in excess of 20 percent or if the Herfindahl-Hirschman Index (HHI) exceeds 2500. The Commission recognized that there are interactions among the results of each screen under the delivered price test and that some interpretation is required and, in fact, is encouraged.[20]

The Commission defines the relevant market under the delivered price test "by identifying potential suppliers based on market prices, input costs, and transmission availability, and calculates each supplier's economic capacity for each season/load condition."[21] The Commission defines the relevant market to include suppliers with "costs less than or equal to 1.05 times the market price," i.e. those "suppliers that could sell into the destination market at a price less than or equal to 5 percent over the market price."[22] Thus, the relevant market includes all supply that is potentially competitive

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16 *Market-Based Rates For Wholesale Sales Of Electric Energy, Capacity And Ancillary Services By Public Utilities*, Order No. 697, 119 FERC ¶ 61,295 (2007) ("Order No. 697").

17 Order No. 697 at P 111.

18 Order No. 697 at P 106–109.

19 *Id*.

20 *Id*.

21 Order No. 697 at P 106.

22 AEP Order at App. F; *see also* Merger Policy Statement, *mimeo* at 6; Order No. 697 at P 108.

with the supplier and excludes supply that is not potentially competitive with the supplier.

The Commission's market based rates analysis then applies the components of the delivered price test to the relevant market. A supplier fails if the supplier is pivotal (one pivotal supplier test), if it has a market share greater than or equal to 20 percent, or if the Herfindahl-Hirschman Index ("HHI") in the relevant market is greater than or equal to 2500.[23] A supplier is pivotal under the market power test if demand in the relevant market cannot be met without its supply (one pivotal supplier test).

The Commission recognizes the interactions among the multiple analyses under the delivered price test and "encourages the most complete analysis of competitive conditions in the market as the data allow."[24]

For example, passing a single pivotal supplier test does not demonstrate the absence of structural market power because market participants can coordinate their behavior with other suppliers and can do so without overt interaction. The Commission stated:

> Concentration statistics can indicate the likelihood of coordinated interaction in a market. All else being equal, the higher the HHI, the more firms can extract excess profits from the market. Likewise a low HHI can indicate a lower likelihood of coordinated interactions among suppliers and could be used to support a claim of a lack of market power by a seller that is pivotal or does have a 20 percent or greater market share in some or all season/load conditions. For example, a seller with a market share of 20 percent or greater could argue that … it would be unlikely to possess market power in an unconcentrated market (HHI less than 1000).[25]

In a market with an inelastic demand curve, the existence of two jointly pivotal suppliers, regardless of the amount of excess capacity available, does not provide a market structure that will result in a competitive outcome. The 20 percent market share and the HHI screen are also weak screens for structural market power on a stand-alone basis. A market share in excess of 20 percent does not demonstrate market power if the holder of that market share is not jointly pivotal and is unlikely to be able to affect the market price. A market share less than 20 percent does not demonstrate the absence of market power if the holder of that market share is jointly pivotal and is likely to be able

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23 Order No. 697 at P 111.

24 *See* Order No. 697 at PP 111–117; AEP Order at PP 111–12.

25 Order No. 697 at P 111.

to affect the market price. An HHI in excess of 2500 does not demonstrate market power if the relevant owners are not jointly pivotal and are unlikely to be able to affect the market price. An HHI less than 2500 does not demonstrate the absence of market power if the relevant owners are jointly pivotal and are likely to be able to affect the market price.[26]

Higher concentration ratios indicate that comparatively small numbers of sellers dominate a market while lower concentration ratios mean larger numbers of sellers split market sales more equally. Lower aggregate market concentration ratios establish neither that a market is competitive nor that participants are unable to exercise market power. Higher concentration ratios do, however, indicate an increased potential for participants to exercise market power. Despite their significant limitations, concentration ratios provide useful information on market structure.

The residual supply index (RSI) is a measure of the extent to which one or more generation owners are pivotal suppliers in a market. A single generation owner is pivotal if the output of the owner's generation facilities is needed to meet demand. Multiple generation owners are jointly pivotal when the output of the owners' generation facilities, taken together, is needed to meet demand. When a generation owner is pivotal, it has the ability to affect market price. For a given level of market demand, the RSI compares the market supply, net of the supply controlled by one or more generation owners, to the market demand. The RSI value is calculated as a ratio, where total supply minus the supply of the tested suppliers is divided by the market demand. If the RSI is greater than 1.00, the supply of the specific generation owner(s) is not needed to meet market demand and that generation owner(s) has a reduced ability to influence market price. If the RSI is less than 1.00, the supply owned by the specific generation owner(s) is needed to meet market demand and the generation owner(s) is a pivotal supplier with an ability to influence price. When the RSI is reported for a market, the reported RSI is for the largest supplier or identified number of the largest suppliers. As with concentration ratios, the RSI is not a bright line test.

FERC indicates that a single supplier RSI of less than 1.0 is an indicator of market power.[27] In the PJM markets a three pivotal supplier RSI of less than 1.0 defines the existence of local market power. The three pivotal supplier test (TPS) defines market

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[26] For detailed examples, see Joseph E. Bowring, PJM market monitor. "IMM Analysis of Combined Regulation Market," PJM Market Implementation Committee Meeting (December 20, 2006).

[27] *See Midwest Independent Transmission System Operator, Inc.*, 121 FERC ¶ 61,190 at P 6 n.5 (2007).

power even in the presence of market share and concentration levels that fall below FERC guidelines for a competitive market structure.[28]

Three Pivotal Supplier Test

In the IMM analysis, the basic metrics used for each market include market share, the Herfindahl-Hirschman Index (HHI) and the three pivotal supplier test (TPS), a residual supplier index used in the PJM markets to define locational market power. Market share measures the proportion of market output contributed by a supplier. Market share is calculated by dividing the output of a supplier by total supply in a market. Concentration ratios are a summary measure of market share. The concentration ratio used here is the Herfindahl-Hirschman Index (HHI), calculated by summing the squares of the market shares of all firms in a market.

The IMM uses the three pivotal supplier test as the key measure of market structure and structural market power. The three pivotal supplier test is used in PJM markets to define the existence of local market power and as a trigger for market power mitigation. A test for local market power based on the number of pivotal suppliers has a solid basis in economics and is clear and unambiguous to apply in practice. There is no perfect test, but 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. The three pivotal supplier test for local market power is also a reasonable application of the logic contained in the Commission's market power tests.

The three pivotal supplier test, as implemented in PJM markets, is consistent with the Commission's market power tests, encompassed under the delivered price test. The three pivotal supplier test is an application of the delivered price test to the Real-Time Energy Market, the Day-Ahead Energy Market, the Regulation Market and the Reliability Pricing Model (RPM) Capacity Market. The three pivotal supplier test explicitly incorporates the impact of excess supply and implicitly accounts for the impact of the price elasticity of demand in the market power tests. The three pivotal supplier test includes more competitors in its definition of the relevant market than the Commission's delivered price test. While the Commission's delivered price test defines the relevant market to include all offers with costs less than, or equal to, 1.05 times the market price, the 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 three pivotal supplier test is also consistent with the Commission's delivered price test in that it tests for the interaction between individual participant attributes and

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[28] AEP Order at P 111.

features of the relevant market structure. The three pivotal supplier test is an explicit test for the ability to exercise unilateral market power as well as market power via coordinated action which accounts for market shares and the supply-demand balance in the market.

The results of the three pivotal supplier test can differ from the results of the HHI and market share tests. The three pivotal supplier test can show the existence of structural market power when the HHI is less than 2500 and the maximum market share is less than 20 percent. The three pivotal supplier test can also show the absence of market power when the HHI is greater than 2500 and the maximum market share is greater than 20 percent. 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. A market share in excess of 20 percent does not indicate market power if the holder of that market share is not jointly pivotal and is unlikely to be able to affect the market price. A market share less than 20 percent does not indicate the absence of market power if the holder of that market share is jointly pivotal and is likely to be able to affect the market price. Similarly, an HHI in excess of 2500 does not indicate market power if the relevant owners are not jointly pivotal and are unlikely to be able to affect the market price. An HHI less than 2500 does not indicate the absence of market power if the relevant owners are jointly pivotal and are likely to be able to affect the market price.[29]

The three pivotal supplier test was designed in light of actual elasticity conditions in load pockets in wholesale power markets in PJM. The price elasticity of demand is a critical variable in determining whether a particular market structure is likely to result in a competitive outcome. A market with a specific set of market structure features is likely to have a competitive outcome under one range of demand elasticity conditions and a noncompetitive outcome under another set of elasticity conditions. It is essential that market power tests account for actual elasticity conditions and that evaluation of market power tests neither ignore elasticity nor make counterfactual elasticity assumptions. As the Commission stated, "In markets with very little demand elasticity, a pivotal supplier could extract significant monopoly rents during peak periods because customers have few, if any, alternatives."[30] The Commission also stated:

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29 For detailed examples, see Joseph E. Bowring, PJM market monitor. "IMM Analysis of Combined Regulation Market," PJM Market Implementation Committee Meeting (December 20, 2006).

30 AEP Order at P 72).

> In both of these models, the lower the demand elasticity, the higher the mark-up over marginal costs. It must be recognized that demand elasticity is extremely small in electricity markets; in other words, because electricity is considered an essential service, the demand for it is not very responsive to price increases. These models illustrate the need for a conservative approach in order to ensure competitive outcomes for customers because many customers lack one of the key protections against market power: demand response.[31]

The three pivotal supplier test is a reasonable application of the Commission's delivered price test to the case of local markets that are defined by actual conditions in a market based on security-constrained, economic dispatch with locational market pricing and extremely inelastic demand. The three pivotal supplier test explicitly incorporates the relationship between supply and demand in the definition of pivotal, and it provides a clear test for whether excess supply is adequate to offset other structural features of the market and results in an adequately competitive market structure.

TPS Test: Defining the market

The goal of defining the relevant market is to include those producers that actually compete to determine the market price or could actually compete to determine the market price. Conversely, the goal of defining the relevant market is to exclude those units that are not meaningful competitors and therefore do not have an impact on the clearing price. The existence of market power within that defined market depends on the ability of the firm to raise price while continuing to sell its output. A firm cannot successfully increase the market price above the competitive level if competitors would replace its output when it did so.

The Commission definition of the relevant market includes all suppliers which have costs less than or equal to 1.05 times the clearing price. The Commission definition means that, if the marginal unit sets the clearing price based on an offer of $200 per MWh, all units with costs less than, or equal to, $210 per MWh have a competitive effect on the offer of the marginal unit. These units are all defined to be meaningful competitors in the sense that it is assumed that their behavior constrains the behavior of the marginal and inframarginal units. The three pivotal supplier definition means that, if the marginal unit sets the clearing price based on an offer of $200 per MWh, all units with costs less than, or equal to, $300 per MWh have a competitive effect on the offer of the marginal unit. These units are all defined to be meaningful competitors in the sense that it is assumed that their behavior constrains the behavior of the marginal and inframarginal units. The three pivotal supplier test incorporates a definition of

31 *Id*. at P 103.

meaningful competitors that is at the extremely high end of inclusive. It is questionable whether a unit with a competitive offer price of $300 offer meaningfully constrains the offer of a $200 unit. This broad market definition is combined with the recognition that multiple owners can be jointly pivotal. The three pivotal supplier test includes three pivotal suppliers while the Commission test includes only one pivotal supplier.

The three pivotal supplier test is designed to test the relevant market. For example, in the case of the market for out of merit generation needed to relieve a constraint in real time, the three pivotal supplier test examines the market specifically available to provide that relief. Under these conditions, the three pivotal supplier test measures the degree to which the supply from three generation suppliers is required in order to meet the demand to relieve a constraint, as defined by PJM's market solution software. The market demand consists of the incremental, effective MW required to relieve the constraint. The market supply consists of the incremental, effective MW of supply available to relieve the constraint.[32] For purposes of the test, incremental effective MW are attributed to specific suppliers on the basis of their control of the assets in question. Generation capacity controlled directly or indirectly through affiliates or through contracts with third parties are attributed to a single supplier.

Unlike structural tests that define markets by geographic proximity, TPS makes explicit and direct use of the incremental, effective MW of supply available to relieve the constraint at a distribution factor (DFAX) greater than, or equal to, the DFAX used by PJM in operations. Only the supply that is part of the market as defined by the reality of the electric network as measured by unit characteristics and distribution factors is included in the three pivotal supplier test, to the extent that it is incremental, effective MW of supply that is available at a price less than, or equal to, 1.5 times the clearing price (P_c) that would result from the intersection of demand (constraint relief required) and the incremental supply available to resolve the constraint.

Energy Market Results

The analysis of the impact of the merger on the energy market focuses on constraint defined locational markets that occurred for 100 or more hours in the 2012-2013

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32 A unit's contribution toward effective, incrementally available supply is based on the DFAX of the unit relative to the constraint and the unit's incrementally available capacity over current load levels, if the capacity in question is available within the period that the relief will be needed. Effective, incrementally available MW from an unloaded 100 MW 15-minute start combustion turbine (CT) with a DFAX of 0.05 to a constraint would be 5 MW relative to the constraint in question. Effective, incrementally available MW from a 200 MW steam unit, with 100 MW loaded, a 50 MW ramp rate and a DFAX of 0.5 to the constraint would be 25 MW.

planning year. The relevant markets in the 2012-2013 planning year may be defined in two ways. The relevant markets may be defined based on the incremental, effective MW of raise relief supply available to relieve each market defining constraint based on the actual operation of PJM's system. This definition of the market allows the identification of resource owners in a position to exercise market power by directly affecting locational prices when a transmission constraint binds. In addition, the relevant markets may be defined based on the actual DFAX adjusted real time output of energy resources within each constrained defined market at the time the constraints were binding in the 2012-2013 planning year. This definition of the market allows the identification of resource owners in a position to benefit from the exercise of market power because they receive the higher prices paid when a constraint binds.

Markets for Incremental Effective Relief of Constraints

A constraint was included in the analysis only if NRG or Edison Mission Energy had incremental effective MW of supply for the constraint. The supply defined in each market interval consists of the incremental, effective MW of raise relief supply that are available at a price less than, or equal to, 1.5 times the clearing price that results from the intersection of demand (constraint relief required) and the incremental supply available to resolve the constraint. The resulting measure of effective raise relief supply is termed the relevant effective supply in the market for the relief of the defined constraint. Results are provided for peak, off peak and all hour periods.

Summary Results for Specific Constraints

For the defined markets, the TPS score, market concentration and HHI levels were calculated on a pre merger and a post merger basis for each instance of the market. A market instance exists each time that PJM dispatch software runs the TPS test on the market for incremental relief of a constraint in the real time energy market and either NRG or Edison Mission Energy or both NRG and Edison Mission Energy were in the supply stack for raise relief MW. There can be multiple market instances in an hour and there can be hours with no market instances. Market instance results were rolled up and averaged by hour, with each hourly result termed a market hour event. Market hours with both NRG and Edison Mission Energy in the supply stack are counted as one hour in the analysis.

Pivotal Supplier Analysis

The three pivotal supplier (TPS) test measures the degree to which the supply from three suppliers of raise help constraint relief is required in order to meet the demand for relief of the constraint. The analysis includes TPS statistics for the identified market on a pre merger basis and on a post merger basis. This TPS analysis is of the market for the Lanesville constraint, as this was the only constraint for which both NRG and Mission Energy have significant raise help capability. Lanesville is a 345/138 kV transformer located in central Illinois in the MISO system. Lanesville is within CWLP's local balancing authority area but is owned by Ameren CILCO and is under Ameren CILCO's functional control. Lanesville is located in close electrical proximity to the Kincaid generating station which is in the Commonwealth Edison system 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 TPS results focus on the ability to exercise market power in the PJM energy market, specifically in the market created by the constraint in question.

Table 0-1 and Table 0-2 show, for peak and off peak hours in the 2012-2013 planning year for the Lanesville constraint, the number of real time constraint hours, the number of hours the market was defined in PJM's look ahead software (Market Hours), the number of Market Hours that one or more market participants failed (Hours Failed) the three pivotal supplier test, the number of Market Hours that NRG and/or Edison Mission Energy provided relief supply in the three pivotal supplier test for the Lanesville facility, the pre merger average TPS score of NRG and Edison Mission Energy, the number of Market Hours that NRG and/or Edison Mission Energy failed the TPS test, the average TPS score for a merged NRG and Edison Mission Energy and the number of Market Hours the merged NRG and Edison Mission Energy would fail the test. Failure of a test in a Market Hour results in the failure of the hour. In all cases the TPS scores and metrics are in terms of the market for raise help relief relative to the Lanesville constraint. Table 0-1 provides the results for peak hours, Table 0-2 provides the result for off-peak hours.

While the tables show that proposed merger would have no impact on the number of hours that participants in the Lanesville market for raise help constraint relief would fail the TPS test, the tables also show that pre-merger, both NRG and Edison Mission Energy have, independently, market power in the Lanesville market for raise help constraint relief. The evidence also indicates that the pre merger market for the Laneville raise help relief is heavily concentrated with Mission Energy holding a dominant position in raise help relief capability. Of the 296 market hours for raise help relief, 295 hours (99.7 percent of market hours) had one or more participants failing the three pivotal supplier test in this market. NRG or Mission Energy, or both, provided supply to the raise help market for Lanesville in 283 of these 296 market hours. Mission Energy, alone, failed the three pivotal supplier test in 282 of the 283 defined market hours in which it provided potential supply (99.6 percent of relevant hours) for raise help relief of Lanesville. NRG failed the three pivotal supplier test in 12 of the 283 relevant market hours The 12 hours that NRG failed the test were concurrent with hours that Mission Energy also failed the test.

There were 282 hours in which either NRG or Mission Energy, or both, failed the three pivotal supplier test pre merger. Post merger, the analysis indicates that the combined company would fail the three pivotal supplier test in the same 282 hours, but, as indicated in the HHI analysis, the combined company would control a larger portion of the available raise help supply for Lanesville. The results show a highly concentrated market pre-merger where one of the merging companies, Mission Energy, holds a dominant position, and the other merging company, NRG, holds a substantial position. While the number of hours that the combined company would be pivotal did not increase, the incentives to exercise market power would increase with the increasing proportion of local supply.

Table 0-1 Peak hours pre and post merger NRG and Edison Mission Energy average TPS scores and number of hours failed by facility

				Pre Merger						Post Merger			Change	
Facility	Total RT Constraint Hours	Number of Market Hours (all companies)	Number of Hours Failed (all companies)	Market Hours (NRG or Mission Energy supply)	Average TPS Score NRG	Average TPS Score Mission Energy	NRG Hours Failed	Mission Energy Hours Failed	Hours when NRG and/or Mission Energy Failed	Market Hours Failed (cases with all companies)	Hours Combined Company Fails	Average TPS Score Combined Company	Change in hours failed (all companies)	Change in hours failed (NRG and/or Mission Energy)
Lanesville	221	240	239	229	0.00	0.02	11	228	228	239	228	0.02	0	0

Table 0-2 Off peak hours pre and post merger NRG and Edison Mission Energy average TPS scores and number of hours failed by facility

				Pre Merger						Post Merger			Change	
Facility	Total RT Constraint Hours	Number of Market Hours (all companies)	Number of Hours Failed (all companies)	Market Hours (NRG or Mission Energy supply)	Average TPS Score NRG	Average TPS Score Mission Energy	NRG Hours Failed	Mission Energy Hours Failed	Hours when NRG and/or Mission Energy Failed	Market Hours Failed (cases with all companies)	Hours Combined Company Fails	Average TPS Score Combined Company	Change in hours failed (all companies)	Change in hours failed (NRG and/or Mission Energy)
Lanesville	39	56	56	54	0.00	0.00	1	54	54	56	54	0.00	0	0

HHI Analysis

Table 0-3, Table 0-4 and Table 0-5 show the minimum, average, maximum and median pre and post merger market hour event HHIs for the Lanesville constraint for which Edison Mission Energy or NRG provided raise help relief supply in the 2012-2013 planning year. Table 0-3 provides the results for peak hours, Table 0-4 provides the results for off-peak hours and Table 0-5 provides the results for all hours.

The HHI results show that the market for Lanesville raise help relief is highly concentrated. The average pre merger HHI for all relevant hours (peak and offpeak) is 7836, well above the 1800 threshold for a highly concentrated market. The median HHI for all relevant hours (peak and offpeak) is 7904. The maximum HHI in the period was 10000. The results show that the merger would increase the average peak market hour HHI by 66 points from 7554 to 7620, a significant increase in the average HHI at these high average concentration levels.

Table 0-3 Peak hours pre and post merger market event HHIs by constraint

		Pre Merger HHI					Post Merger HHI					Change in HHI				
Facility	Market Hours	Min	Mean	Max	Median	Standard Deviation	Min	Mean	Max	Median	Standard Deviation	Min	Mean	Max	Median	Standard Deviation
Lanesville	229	2197	7554	10000	7505	1740	2197	7620	10000	7554	1696	-	66	-	48	(45)

Table 0-4 Off peak hours pre and post merger market event HHIs by constraint

		Pre Merger HHI					Post Merger HHI					Change in HHI				
Facility	Market Hours	Min	Mean	Max	Median	Standard Deviation	Min	Mean	Max	Median	Standard Deviation	Min	Mean	Max	Median	Standard Deviation
Lanesville	54	5028	9028	10000	9981	1523	5028	9034	10000	9981	1513	-	7	-	-	(11)

Table 0-5 All hours pre and post merger market event HHIs by constraint

		Pre Merger HHI					Post Merger HHI					Change in HHI				
Facility	Market Hours	Min	Mean	Max	Median	Standard Deviation	Min	Mean	Max	Median	Standard Deviation	Min	Mean	Max	Median	Standard Deviation
Lanesville	283	2197	7836	10000	7904	1795	2197	7890	10000	7932	1750	-	55	-	28	(44)

Specific Constrained Market Results

Table 0-6 shows, for the Lanesville constraint, the pre merger market event hour HHI category, the number of market event hours where the proposed merger would have increased the HHI by 50 or more points, 100 or more points, 200 or more points and/or 300 or more points.

Table 0-6 shows that all of the 283 relevant market hours for which Edison Mission Energy or NRG provided raise help relief supply for the Lanesville constraint in the 2012-2013 planning year had a pre merger HHI of 2000 or more and 277 of these market hours (97.9 percent of relevant market hours) had a pre merger HHI of 4000 or more.

Of the 277 pre merger Lanesville market event hours with an HHI of 4000 or more, the merger would cause eleven of these market event hours to have an increase of 200 or more points and ten of these market event hours to have an increase of 300 or more points. These are the market hours where both NRG and Mission Energy concurrently provided raise help relief supply for the Lanesville constraint in the 2012-2013 planning period.

The TPS results, in combination with the HHI results, indicate that Mission Energy holds a dominant position in the heavily concentrated market for raise help relief capability for the Lanesville constraint and that the merger with NRG would, in a small subset of hours, significantly exacerbate this dominant position, increasing the incentive and the ability, to exercise market power in this local market. The combined company 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.

Lanesville Results

Table 0-6 By pre merger market event HHI category, post merger change in HHI of 50 or more, 100 or more, 200 or more or 300 or more points: Lanesville Market 2012-2013 planning year

HHI Range	Pre Merger Number of Market Hours	Post Merger Number of Market Hours	Change in Hours	Pre to Post Merger hours with HHI increase of 50 or more	Pre to Post Merger hours with HHI increase of 100 or more	Pre to Post Merger hours HHI increase of 200 or more	Pre to Post Merger hours with HHI increase of 300 or more	Percentage of Market Hours with HHI increase of 50 or more	Percentage of Market Hours with HHI increase of 100 or more	Percentage of Market Hours with HHI increase of 200 or more	Percentage of Market Hours with HHI increase of 300 or more	Pre Merger Percentage of Makret Hours in HHI Range	Post Merger Percentage of Hours in HHI Range	Change in percentage of hours in HHI range
<500	-	-	-	-	-	-	-	-	-	-	-	0%	0%	0%
500 to <1000	-	-	-	-	-	-	-	-	-	-	-	0%	0%	0%
1000 to <1500	-	-	-	-	-	-	-	-	-	-	-	0%	0%	0%
1500 to <2000	-	-	-	-	-	-	-	-	-	-	-	0%	0%	0%
2000 to <2500	2	2	-	-	-	-	-	0%	0%	0%	0%	1%	1%	0%
2500 to <3000	3	3	-	-	-	-	-	0%	0%	0%	0%	1%	1%	0%
3000 to <3500	-	-	-	-	-	-	-	-	-	-	-	0%	0%	0%
3500 to <4000	1	1	-	-	-	-	-	0%	0%	0%	0%	0%	0%	0%
4000 to <4500	5	4	(1)	1	1	1	1	20%	20%	20%	20%	2%	1%	0%
4500 to <5000	4	2	(2)	2	2	2	2	50%	50%	50%	50%	1%	1%	-1%
5000 to <5500	13	12	(1)	1	1	1	1	8%	8%	8%	8%	5%	4%	0%
5500 to <6000	13	11	(2)	2	2	2	2	15%	15%	15%	15%	5%	4%	-1%
6000 to <6500	26	27	1	1	1	1	1	4%	4%	4%	4%	9%	10%	0%
6500 to <7000	32	31	(1)	3	3	3	3	9%	9%	9%	9%	11%	11%	0%
7000 to <7500	25	28	3	-	-	-	-	0%	0%	0%	0%	9%	10%	1%
7500 to <8000	22	23	1	-	-	-	-	0%	0%	0%	0%	8%	8%	0%
8000 to <8500	23	23	-	1	1	1	-	4%	4%	4%	0%	8%	8%	0%
8500 to <9000	20	22	2	-	-	-	-	0%	0%	0%	0%	7%	8%	1%
9000 to <9500	15	15	-	-	-	-	-	0%	0%	0%	0%	5%	5%	0%
9500 to <10000	34	34	-	-	-	-	-	0%	0%	0%	0%	12%	12%	0%
10000	45	45	-	-	-	-	-	0%	0%	0%	0%	16%	16%	0%
Overall	283	283	-	11	11	11	10	4%	4%	4%	4%	100%	100%	0%

Capacity Market Results

The Reliability Pricing Model (RPM) Capacity Market design was implemented in the PJM region on June 1, 2007. RPM is a forward-looking, annual, locational market, with a must offer requirement for capacity and a must buy requirement for load, with performance incentives for generation, that includes clear market power mitigation rules and that permits the direct participation of demand-side resources.

Under RPM, capacity obligations are annual. Base Residual Auctions (BRA) are held for delivery years that are three years in the future. Effective with the 2012/2013 delivery year, First, Second and Third Incremental Auctions (IA) are held for each delivery year.[33]

RPM prices are locational and may vary depending on transmission constraints and local supply and demand conditions.[34] Existing generation capable of qualifying as a capacity resource must be offered into RPM Auctions, except for resources owned by

33 See 126 FERC ¶ 61,275 (2009) at P 86.

34 Transmission constraints are local capacity import capability limitations caused by transmission facility limitations, voltage limitations or stability limitations. In RPM, capacity constraints are measured by the relationship between capacity emergency transfer limits (CETL) and capacity emergency transfer objectives (CETO) for LDAs.

entities that elect the fixed resource requirement (FRR) option, which is a way to opt out of RPM while maintaining responsibility for meeting capacity obligations. Participation by LSEs is mandatory, except for those entities that elect the FRR option. There is an administratively determined demand curve that, with the supply curve derived from capacity offers, determines market prices in each BRA. RPM rules provide performance incentives for generation, which, although not adequate, link capacity payments to the level of unforced capacity and link capacity payments to the performance of capacity resources during identified hours. Under RPM there are explicit market power mitigation rules that define the must offer requirement, that define structural market power, that define offer caps based on the marginal cost of capacity and that have flexible criteria for competitive offers by new entrants or by entrants that have an incentive to exercise monopsony power. Demand-side resources and Energy Efficiency resources may be offered directly into RPM Auctions and receive the clearing price without mitigation.

In the Capacity Market, transmission constraints mean that less expensive capacity from unconstrained parts of PJM is not always available in constrained parts of PJM. The higher capacity prices that result when transmission constraints are binding reflect the higher marginal costs of capacity located in the constrained areas which is needed to meet the requirement for capacity in the constrained areas at those times. Under these conditions, a single capacity price for the entire PJM footprint would not provide the appropriate incentives to build or maintain capacity in constrained areas when capacity is needed to maintain reliability and meet the loads there. When transmission constraints create local capacity markets in specific RPM Locational Deliverability Areas (LDAs) and the TPS test is failed, there is structural market power in those local markets.

Capacity markets are necessary in PJM in order to ensure that the incentives are adequate to provide the desired level of reliability.[35] Energy market net revenues are not adequate to keep a significant portion of existing units, across all technology types, financially viable. Net revenues from the energy market alone are less than the annual going forward costs for a significant level of capacity, across all generation technologies. When a unit receives less than its annual going forward costs in net revenue, it is more profitable for the unit to retire than to continue operation. Capacity market revenues make up that difference and provide the incentive for units to continue operation.[36]

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35 *See* the *2012 State of the Market Report for PJM*, Volume II, Section 4, "Capacity Market," for a more detailed discussion.

36 *See* the *2012 State of the Market Report for PJM*, Volume II, Section 6, "Net Revenue."

In addition, energy market net revenues are not sufficient to incent new entry. The net revenues from the energy market are less than the annual going forward costs plus annual fixed costs of new units. In some zones, the sum of capacity market revenues and energy market net revenues is adequate to incent new entry. In those cases, capacity market revenues make up the difference and provide a key component of the incentive for new entry.[37]

The RPM Capacity Market design explicitly addresses the underlying issues of ensuring that competitive prices can reflect local scarcity while not relying on the exercise of market power to achieve the design objective, and of explicitly limiting the exercise of market power.

The 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. The market may be long at times, but that is not the equilibrium state. Capacity in excess of demand is not sold and, if it does not earn adequate revenues in other markets, will retire. 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.

In other words, the market design for capacity leads, almost unavoidably, to structural market power. Given the basic features of market structure in the PJM Capacity Market, including significant market structure issues, inelastic demand, tight supply-demand conditions, the relatively small number of nonaffiliated LSEs and supplier knowledge of aggregate market demand, the potential for the exercise of market power is high. Market power is and will remain endemic to the existing structure of the PJM Capacity Market. This is not surprising in that the Capacity Market is the result of a regulatory/administrative decision to require a specified level of reliability and the related decision to require all load serving entities to purchase a share of the capacity required to provide that reliability. It is important to keep these basic facts in mind when evaluating capacity markets. The Capacity Market is unlikely ever to approach the economist's view of a competitive market structure in the absence of a substantial and unlikely structural change that results in much more diversity of ownership.

RPM has explicit market power mitigation rules designed to permit competitive, locational capacity prices while limiting the exercise of market power. The RPM construct is consistent with the appropriate market design objectives of permitting

37 *See* the *2012 State of the Market Report for PJM*, Volume II, Section 6, "Net Revenue."

competitive prices to reflect local scarcity conditions while explicitly limiting market power. 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.

But it must also be recognized that the market power mitigation rules are not perfect and cannot prevent all exercises of market power.

Markets

The analysis of the impact of the merger on the Capacity Market examines the locational markets defined by the underlying economics of the market including supply and demand curves and transmission constraints. Each transmission zone is a Locational Deliverability Area (LDA) which can be a separate market if PJM models the zone as an LDA and market conditions result in price separation in an auction. There are, in addition, several subzonal LDAs, including PSEG North, DPL South, and ATSI Cleveland.

For the defined markets, market concentration and HHI levels were calculated on a pre merger and a post merger basis for each market.

As in the energy market, to the extent that total RTO demand for capacity can be met without any constraints binding, the optimal solution is defined by the intersection of the aggregate supply and demand curves. However, if the next increment of demand for capacity in an LDA cannot be met by the next economic increment of supply, regardless of location, and must be met by supply within the LDA, then the transmission constraint is binding and there is a separate market created. That separate market is defined by the incremental demand that must be met by capacity within the LDA and the incremental supply within the LDA available to meet that demand, above that which would have cleared at the RTO price.

The ability to exercise market power in the LDA is determined by the ownership structure of the incremental supply and the relationship between incremental supply and incremental demand. The ability to exercise market power can be measured most accurately by the TPS test, applied to the incremental supply of capacity, but can also be measured by the HHI, applied to the total cleared supply of capacity in the LDA. The incentive to exercise market power in the LDA is a function of the ownership structure of all capacity in the LDA. Regardless of offer price and regardless whether the capacity was incremental, all capacity in a constrained LDA receives the higher constrained clearing price. The ability to exercise market power can be measured most accurately by the TPS test while the HHI provides a measure of the incentive to exercise market power.

When RPM clears as a single market, total RTO supply and demand determine the clearing price and all resources receive the clearing price. The market definition is clear. When an LDA within the RTO clears as a separate market, the incremental locational supply available to meet the locational demand determines the clearing price for the LDA. All capacity resources in the LDA receive the clearing price, regardless of whether the capacity resources are incremental.

When there are multiple LDAs that clear as separate markets and the LDAs are not overlapping, the logic is exactly the same for each LDA separately and its relationship to the rest of RTO. When the LDAs are nested, one within another, the analysis becomes more complex. For example, EMAAC is entirely within MAAC, which is entirely within the RTO. The EMAAC locational price is determined by the incremental locational supply available to meet the locational demand within EMAAC. The MAAC price in this case is analogous to the RTO price in the case of a single LDA. The MAAC price is determined by all the MAAC incremental supply (defined with respect to the RTO market) that is not incremental in EMAAC. Even though MAAC includes more capacity resources than EMAAC, the MAAC clearing price may result from fewer MW of incremental supply than the EMAAC price and may apply to fewer MW of rest of MAAC supply than the EMAAC price. The MAAC clearing price in this case could also be referred to as the rest of MAAC price, analogous to the rest of RTO price. The rest of RTO clearing price in this case is determined by all the supply that is not incremental in MAAC, including EMAAC.

Total Market Analysis

HHI Analysis

Table 0-7 shows pre and post merger HHIs for the 2015/2016 and 2016/2017 RPM Base Residual Auctions, including all constrained LDAs for each BRA.[38] The HHIs in Table 0-7 measure concentration of ownership for all capacity in the identified LDAs. This metric measures the incentive to exercise market power rather than the ability to exercise market power in the constrained LDAs. Table 0-7 also shows the change in HHI and whether the change was between 50 and 100 points, 100 to 200 points, 200 to 300 points or exceeded 300 points. As a result of the location of the capacity resources of the two companies there was a change in HHI only for the RTO market and that increase was less than 50 points.

[38] For the HHI analysis the sell offers were adjusted to include the withdrawn deactivations of Avon Lake 7, Avon Lake 9, New Castle 3, New Castle 4, New Castle 5, New Castle Diesel and Gilbert 8 units; to reflect the fact that EME no longer owns the Homer City plant; and to remove sell offers for resources that are no longer capacity resources as of December 2013.

Table 0-7 Post merger total market HHI analysis

RPM Auction	RPM Market	Pre Merger HHI	Post Merger HHI	Change in HHI	Change in HHI Range: 50 to 100	100 to 200	200 to 300	Greater than or equal to 300
2015/2016 Base Residual Auction	RTO	726	757	31				
	MAAC	1,124	1,124	0				
	ATSI	3,702	3,702	0				
2016/2017 Base Residual Auction	RTO	610	639	28				
	MAAC	951	951	0				
	PSEG	4,621	4,621	0				
	ATSI	2,632	2,632	0				

Incremental Market Analysis

Pivotal Supplier Analysis

The incremental analysis addresses the ability of owners to exercise market power.

The market for a constrained LDA is defined by the incremental supply available to meet the incremental demand when locational incremental demand must be met by capacity resources within the LDA. The RTO market is defined 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 RTO.

The three pivotal supplier (TPS) test measures the degree to which the incremental supply from three suppliers of capacity is required in order to meet the incremental demand in an LDA. 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.

Table 0-8 includes TPS statistics for the identified markets on a pre merger basis and a post merger basis.[39]

The TPS scores for all the identified markets were less than 1.00, indicating failure of the TPS test.

Table 0-8 shows that the merger would reduce TPS scores, indicating the merger would exacerbate the structural market power issues and increase the ability of the post merger company to exercise market power in the RTO market, although these effects are not large.

39 For the TPS analysis the sell offers were adjusted to include the withdrawn deactivations of Avon Lake 7, Avon Lake 9, New Castle 3, New Castle 4, New Castle 5, New Castle Diesel and Gilbert 8 units; to reflect the fact that EME no longer owns the Homer City plant; and to remove sell offers for resources that are no longer capacity resources as of December 2013.

Table 0-8 Pre and post merger TPS analysis

RPM Auction	RPM Market	Pre Merger RSI_3	Post Merger RSI_3	Change in RSI_3	Percent Change
2015/2016 Base Residual Auction	RTO	0.546	0.529	(0.016)	(2.9%)
	MAAC	0.668	0.668	0.000	0.0%
	ATSI	0.000	0.000	0.000	0.0%
2016/2017 Base Residual Auction	RTO	0.597	0.577	(0.021)	(3.5%)
	MAAC	0.380	0.380	0.000	0.0%
	PSEG	0.000	0.000	0.000	0.0%
	ATSI	0.000	0.000	0.000	0.0%

Table 0-9 Pre and post merger TPS scores by cleared LDA by RPM Base Residual Auction: NRG, Edison Mission Energy and Combined

		Pre Merger RSI_3		Post Merger RSI_3
RPM Auction	RPM Market	NRG	Edison Mission	Merged Company
2015/2016 Base Residual Auction	RTO	0.553	0.602	0.529
	MAAC	0.668		0.668
	ATSI			
2016/2017 Base Residual Auction	RTO	0.597	0.649	0.577
	MAAC	0.405		0.405
	PSEG			
	ATSI			

Regulation Market Results

The analysis of the impact of the merger on the Regulation Market examines the Regulation Market hours when either Edison Mission Energy or NRG supplied and cleared regulation MW in the period from October 1, 2012 through September 30, 2013.[40] These are the relevant regulation markets. A market hour exists each time that PJM dispatch software runs and clears the regulation market. The IMM's calculated HHI levels on a pre merger and a post merger basis for each market hour. The analysis indicated that the proposed merger raises significant market power concerns in the regulation market.

Table 0-10 shows pre and post merger HHIs for the relevant regulation market for October 2012 through September 2013. The table shows that, overall, the regulation market affected by NRG and Edison Mission Energy resources is highly concentrated. Pre-merger terms, 53.1 percent of the market hours affected by NRG and Edison Mission Energy resources had an HHI of 1800 or more, 37.6 percent had an HHI of 2000 or more and 12.9 percent of the market hours had an HHI of 2500 or more. Post merger, 55.6

[40] This period was chosen to align with the significant changes to the Regulation Market which were implemented on October 1, 2012.

percent of these market hours would have had an HHI of 1800 or more, 38.9 percent would have an HHI of 2000 or more, and 13.3 percent of the market hours would have an HHI of 2500 or more.

Table 0-10 shows that of the 2,280 pre merger market hours in the 2000 or more HHI range, the merger would have caused the HHI in 189 of these market hours to increase by 50 or more points, 61 of these market hours to increase by 100 or more points, 12 of these market hours to increase by 200 or more points and 1 of these market hours to increase by 300 or more points. The HHI results indicate that the regulation market is highly concentrated in a significant number of relevant market hours and that the merger would significantly increase concentration levels in a significant number of these hours.

Table 0-10 Pre and post merger market hour HHIs: Regulation Market October 2012 through September 2013

Range	Pre Merger Number of Market Hours	Post Merger Number of Market Hours	Change In Hours	Pre to Post Merger HHI Increase of 50 or More	Pre to Post Merger HHI Increase of 100 or More	Pre to Post Merger HHI Increase of 200 or More	Pre to Post Merger HHI Increase of 300 or More	Percentage of Market Hours with HHI Increase of 50 or More	Percentage of Market Hours with HHI Increase of 100 or More	Percentage of Market Hours with HHI Increase of 200 or More	Percentage of Market Hours with HHI Increase of 300 or More	Pre Merger Percentage of Market Hours in HHI Range	Post Merger Percentage of Market Hours in HHI Range	Change in Percentage of Hours in HHI Range
<500	0	0	0	0	0	0	0	-	-	-	-	0%	0%	0%
500 to <1000	26	7	-19	0	0	0	0	0%	0%	0%	-	0%	0%	0%
1000 to <1500	1327	1156	-171	431	190	34	3	32%	14%	3%	0%	22%	19%	-3%
1500 to <2000	2423	2536	113	569	232	35	1	23%	10%	1%	0%	40%	42%	2%
2000 to <2500	1493	1553	60	161	55	11	1	11%	4%	1%	0%	25%	26%	1%
2500 to <3000	599	616	17	24	5	0	0	4%	1%	0%	0%	10%	10%	0%
3000 to <3500	147	145	-2	2	0	0	0	1%	0%	0%	0%	2%	2%	0%
3500 to <4000	35	37	2	2	1	1	0	6%	3%	3%	0%	1%	1%	0%
4000 to <4500	3	3	0	0	0	0	0	0%	0%	-	-	0%	0%	0%
4000 to <4500	3	3	0	0	0	0	0	0%	0%	-	-	0%	0%	0%
5000 to <5500	0	0	0	0	0	0	0	-	-	-	-	0%	0%	0%
5500 to <6000	0	0	0	0	0	0	0	-	-	-	-	0%	0%	0%
6000 to <6500	0	0	0	0	0	0	0	-	-	-	-	0%	0%	0%
6500 to <7000	0	0	0	0	0	0	0	-	-	-	-	0%	0%	0%
7000 to <7500	0	0	0	0	0	0	0	-	-	-	-	0%	0%	0%
7500 to <8000	0	0	0	0	0	0	0	-	-	-	-	0%	0%	0%
8000 to <8500	0	0	0	0	0	0	0	-	-	-	-	0%	0%	0%
8500 to <9000	0	0	0	0	0	0	0	-	-	-	-	0%	0%	0%
9000 to <9500	0	0	0	0	0	0	0	-	-	-	-	0%	0%	0%
9500 to <10000	0	0	0	0	0	0	0	-	-	-	-	0%	0%	0%
10000	0	0	0	0	0	0	0	-	-	-	-	0%	0%	0%
Overall	6056	6056	0	1189	483	81	5	20%	8%	1%	0%	100%	100%	0%

Appendix A: List of NRG Units

Unit Name	Unit ID	Participant Name	Unit Type
COM AURORA CT 1 (PE)	86012101	RESA	CT
COM AURORA CT 10 (RL)	86012110	RESA	CT
COM AURORA CT 2 (PE)	86012102	RESA	CT
COM AURORA CT 3 (PE)	86012103	RESA	CT
COM AURORA CT 4 (PE)	86012104	RESA	CT
COM AURORA CT 5 (RL)	86012105	RESA	CT
COM AURORA CT 6 (RL)	86012106	RESA	CT
COM AURORA CT 7 (RL)	86012107	RESA	CT
COM AURORA CT 8 (RL)	86012108	RESA	CT
COM AURORA CT 9 (RL)	86012109	RESA	CT
COM ROCKFORD CT 11	86262101	NRGPM	CT
COM ROCKFORD CT 12	86262102	NRGPM	CT
COM ROCKFORD CT 21	86262103	NRGPM	CT
DPL GN F 1 F	80100101	NRGPM	STEAM
DPL IN R 10 CT	80032205	NRGPM	CT
DPL IN R 3 F	80030103	NRGPM	STEAM
DPL IN R 4 F	80030104	NRGPM	STEAM
DPL KENT 1 CT	80512101	NRGPM	CT
DPL KENT 2 CT	80512102	NRGPM	CT
DPL VIEN 10 CT	80042202	NRGPM	CT
DPL VIEN 8 F	80040108	NRGPM	STEAM
DUQ BRUNOT IS 1A CT	97032111	ORION	CT
DUQ BRUNOT IS 2A CT	97032121	REESBI	CT
DUQ BRUNOT IS 2B CT	97032122	REESBI	CT
DUQ BRUNOT IS 3 CT	97032130	REESBI	CT
DUQ BRUNOT IS 4 CC	97030104	REESBI	STEAM
DUQ CHESWICK 1	97040101	ORION	STEAM
DUQ PATTERSON DAM	97084101	ORION	HYDRO
DUQ TOWNSEND DAM	97094101	ORION	HYDRO
FE AVON 10 CT	54020103	ORION	CT
FE AVON 7 F	54020102	ORION	STEAM
FE AVON 9 F	54020101	ORION	STEAM
FE NEW CASTLE 1-2 D	54060101	ORION	DIESEL
FE NEW CASTLE 3 F	54060104	ORION	STEAM
FE NEW CASTLE 4 F	54060105	ORION	STEAM
FE NEW CASTLE 5 F	54060103	ORION	STEAM
FE NILES CTA	54070103	ORION	CT
JC GILB 1 CT	51012110	REMA	CT
JC GILB 2 CT	51012120	REMA	CT
JC GILB 3 CT	51012130	REMA	CT
JC GILB 4 CT	51012140	REMA	CT
JC GILB 4C CC	51012740	REMA	CT
JC GILB 5C CC	51012750	REMA	CT
JC GILB 6C CC	51012760	REMA	CT

Unit Name	Unit ID	Participant Name	Unit Type
JC GILB 7C CC	51012770	REMA	CT
JC GILB 8+N F	51010280	REMA	STEAM
JC GILB GIL9 CT	51012109	REMA	CT
JC GLEN CT1 CT	51052110	REMA	CT
JC GLEN CT2 CT	51052120	REMA	CT
JC GLEN CT3 CT	51052130	REMA	CT
JC GLEN CT4 CT	51052140	REMA	CT
JC GLEN CT5 CT	51052150	REMA	CT
JC GLEN CT6 CT	51052160	REMA	CT
JC GLEN CT7 CT	51052170	REMA	CT
JC GLEN CT8 CT	51052180	REMA	CT
JC SAYV CT1 CT	51022110	REMA	CT
JC SAYV CT2 CT	51022120	REMA	CT
JC SAYV CT3 CT	51022130	REMA	CT
JC SAYV CT4 CT	51022140	REMA	CT
JC WERN CT1 CT	51032110	REMA	CT
JC WERN CT2 CT	51032120	REMA	CT
JC WERN CT3 CT	51032130	REMA	CT
JC WERN CT4 CT	51032140	REMA	CT
ME HAMT 1 CT	52462110	REMA	CT
ME HUNT 1 CT	52412110	REMA	CT
ME HUNT 2 CT	52412120	REMA	CT
ME HUNT 3 CT	52412130	REMA	CT
ME MTN 1 CT	52472110	REMA	CT
ME MTN 2 CT	52472120	REMA	CT
ME ORRT 1 CT	52422110	REMA	CT
ME PORT 1 F	52440110	REMA	STEAM
ME PORT 2 F	52440120	REMA	STEAM
ME PORT 3 CT	52442130	REMA	CT
ME PORT 4 CT	52442140	REMA	CT
ME PORT 5 CT	52442150	REMA	CT
ME SHAW 1 CT	52452110	REMA	CT
ME TOLN 1 CT	52482110	REMA	CT
ME TOLN 2 CT	52482120	REMA	CT
ME TTUS 4 CT	52432140	REMA	CT
ME TTUS 5 CT	52432150	REMA	CT
ME HUNT CC11	52410110	RESH	STEAM
ME HUNT CC21	52410120	RESH	STEAM
NUG PACR NUG F	32050101	NRGPM	STEAM
PEP CHPT 1 CT	60052211	METMA	CT
PEP CHPT 1 F	60050101	METMA	STEAM
PEP CHPT 2 CT	60052112	METMA	CT
PEP CHPT 2 F	60050102	METMA	STEAM
PEP CHPT 3 CT	60052113	METMA	CT
PEP CHPT 3 F	60050103	METMA	STEAM
PEP CHPT 4 CT	60052114	METMA	CT
PEP CHPT 4 F	60050104	METMA	STEAM
PEP CHPT 5 CT	60052115	METMA	CT

Unit Name	Unit ID	Participant Name	Unit Type
PEP CHPT 6 CT	60052116	METMA	CT
PEP CHPT SMEC CT	60052131	METMA	CT
PEP DICK 1 CT	60042211	METMA	CT
PEP DICK 1 F	60040101	METMA	STEAM
PEP DICK 2 F	60040102	METMA	STEAM
PEP DICK 3 F	60040103	METMA	STEAM
PEP DICK H 1 CT	60042131	METMA	CT
PEP DICK H 2 CT	60042132	METMA	CT
PEP MORG 1 CT	60062111	METMA	CT
PEP MORG 1 F	60060101	METMA	STEAM
PEP MORG 2 CT	60062112	METMA	CT
PEP MORG 2 F	60060102	METMA	STEAM
PEP MORG 3 CT	60062113	METMA	CT
PEP MORG 4 CT	60062114	METMA	CT
PEP MORG 5 CT	60062115	METMA	CT
PEP MORG 6 CT	60062116	METMA	CT
PN BLOS 1 CT	53232110	REMA	CT
PN CONM 1 F	53620110	ConmhP	STEAM
PN CONM 2 F	53620120	ConmhP	STEAM
PN CONM A-D D	53623110	ConmhP	DIESEL
PN KEY 1 F	53610110	Keystn	STEAM
PN KEY 2 F	53610120	Keystn	STEAM
PN KEY 3-6 D	53613130	Keystn	DIESEL
PN SHVL 1 F	53210110	REMA	STEAM
PN SHVL 2 F	53210120	REMA	STEAM
PN SHVL 3 F	53210130	REMA	STEAM
PN SHVL 4 F	53210140	REMA	STEAM
PN SHVL 5-7 D	53213150	REMA	DIESEL
PN SWRD 1	53250101	RESS	STEAM
PN WARN 3 CT	53262130	REMA	CT

Appendix B: List of Edison Mission Units

Unit Name	Unit ID	Participant Name	Unit Type
COM BIG SKY 1 WF	86692101	BSKYW	WIND
COM FISK CT 31	86152131	EMMT	CT
COM FISK CT 32	86152132	EMMT	CT
COM FISK CT 33	86152133	EMMT	CT
COM FISK CT 34	86152134	EMMT	CT
COM JOLIET 6	86160106	EMMT	STEAM
COM JOLIET 7	86160207	EMMT	STEAM
COM JOLIET 8	86160208	EMMT	STEAM
COM POWERTON 5	86240205	EMMT	STEAM
COM POWERTON 6	86240206	EMMT	STEAM
COM WAUKEGAN 7	86320107	EMMT	STEAM
COM WAUKEGAN 8	86320108	EMMT	STEAM
COM WAUKEGAN CT 31-32	86322131	EMMT	CT
COM WILL COUNTY 3	86330103	EMMT	STEAM
COM WILL COUNTY 4	86330104	EMMT	STEAM
PN LOOKOUT WF 1	53723102	EMMT	WIND
AP PINNACLE 1 WF	90832801	EMTPIN	WIND

Attachment B

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

COMMENTS OF
THE INDEPENDENT MARKET MONITOR FOR PJM

Pursuant to Rule 211 of the Commission's Rules and Regulations,[1] Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor for PJM ("Market Monitor"),[2] submits these comments on the joint application of NRG Energy Holdings Inc. ("NRG") and Edison Mission Energy ("EME") for approval of a transaction whereby NRG would acquire substantially all of the assets of EME, as amended by applicants response dated December 16, 2013, to the Commission notice of deficiency issued December 5, 2013. In its pleading dated December 9, 2013, the Market Monitor provided an alternative analysis and comments in a report ('December 9th Report"). The Market Monitor attaches to this pleading, as an Attachment, an updated report ("January 2nd Report"), which, among other things, conforms some of the analysis to be consistent with the information requested by the Commission in its December 5th notice.

The most significant issues identified in both the December 9th Report and the January 2nd Report relevant to the standards of review applicable to a merger under Section 203 of the Federal Power Act are: ~~is~~ the increase in market power in the PJM Regulation Market that will result from combining the assets of the two companies; and the dominant

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1 18 CFR § 385.211 (2011).

2 Capitalized terms used herein (including the attached report) and not otherwise defined have the meaning used in the PJM Open Access Transmission Tariff ("OATT").

position in a specific local energy market that NRG would gain as a result of the merger. The Market Monitor believes that these~~is~~ issues can be addressed by conditioning approval of the merger on the applicants' adoption of mitigation in the form of behavioral rules applicable to applicants' participation in the PJM Regulation Market and a requirement that the Market Monitor report to the Commission after 12 months on any changes in behavior in the identified local energy market.

I. COMMENTS

A. Updated Report.

The Market Monitor's January 2nd Report~~report~~ provides an assessment of the impact of the proposed merger between NRG and EME on PJM wholesale electricity markets including the Energy Market, the Capacity Market and the Regulation Market. In conducting this analysis the Market Monitor has made use of actual dispatch, offer and availability data to define the relevant markets and to examine the effects of the proposed merger on those markets using concentration ratios and pivotal supplier indices. The Commission has accepted and considered similar analyses when evaluating proposed mergers in PJM.[3]

The analysis presented in this report covers the impact of the proposed merger on the structure of the PJM markets, using current data. The analysis examines market structure metrics in order to quantify the expected impact of the proposed merger on the market structure of constraint defined markets within PJM. The analysis concludes that the proposed merger would significantly increase concentration in a specific, highly concentrated locational energy market, would increase concentration and reduce TPS scores

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[3] *See* 138 FERC ¶ 61,167; *see also Analysis of Horizontal Market Power under the Federal Power Act*, 138 FERC ¶ 61,109 (2012) ("We reiterate, however, that the Commission may consider arguments that a proposed transaction raises competitive concerns that have not been captured by the Competitive Analysis Screen. Likewise, while applicants must continue to provide a Competitive Analysis Screen, we will also consider any alternative methods or factors, if adequately supported.").

in the capacity market although the effect is not large and would significantly increase concentration in the market for regulation.

B. Behavioral Mitigation Is Needed to Address Market Power Issues in the PJM Regulation Market and in a Specific Locational Energy Market.

In both the December 9th Report and the January 2nd Report, the Market Monitor identified an increase in concentration levels in the PJM Regulation Market that would result from combining the assets of NRG and EME. This means that the proposed merger would significantly increase concentration in a specific, highly concentrated locational energy market, would increase concentration and reduce TPS scores in the capacity market although the effect is not large, and would significantly increase concentration in the market for regulation. In its December 9th Report, the Market Monitor recommended that the Commission consider behavioral mitigation, in the form of requirements to engage in competitive offer behavior in each PJM market, to resolve the issues identified.

The proposed merger would have a limited impact on the overall competitiveness of PJM markets, but would have a significant impact on one local energy market and a significant impact on the regulation market. The IMM recommends that the Commission require behavioral mitigation measures to address the issues identified in this report. Appropriate mitigation could resolve the identified concerns about competitive impacts. The IMM recommends that, if the merger is approved, the Commission require the merged company to make cost-based offers in the regulation market and that the Commission require the IMM to report after 12 months on any changes in behavior in the identified local energy market.

The Market Monitor also recommends that the merged company be required to continue to offer the same units and quantities historically offered into the~~se~~ regulation market~~s~~ because participation is voluntary and one way to exercise market power is simply not to offer.

The proposed conditions are proportionally limited in scope and scale to the issues identified in the Market Monitor's analysis. The substance of this condition merely requires that the applicants behave competitively in the PJM Regulation Market, consistent with fundamental Commission regulatory policy. Accordingly, a requirement that the applicants adhere to the proposed behavioral requirements should be made a condition for any approval of the application for merger.

II. CONCLUSION

The Market Monitor respectfully requests that the Commission afford due consideration to these comments as the Commission resolves the issues raised in this proceeding.

Respectfully submitted,

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Dated: January 2, 2014

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Eagleville, Pennsylvania,
this 2nd day of January, 2014.

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Attachment

Table of Contents

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Methods of Analysis

In analyzing whether a proposed merger is consistent with the public interest, the FERC considers the "effect of the transaction on competition, rates, and regulation of the applicant by the Commission and state commissions with jurisdiction over any party to the transaction."[2] In this report, the IMM focuses on the first factor, the effect on competition, measured by the impact on the structure of relevant markets based on actual market data. The IMM evaluates the impact of the merger using concentration thresholds, including those defined in FERC's Competitive Analysis Screen,[3] and pivotal supplier analysis.

Any analysis of market structure depends on an accurate definition of the relevant markets. Market definitions depend on properly identifying and evaluating potential substitutes for a given product. Within organized markets data are available, and should be used, to define markets based on how the units are evaluated and dispatched to meet demand, based on networked relationships between resources and load, relative costs, availability and operational parameters. Such an approach provides definitions of the

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2 18 CFR § 33.2(g) (2011).

3 18 CFR § 33.3; *see also Revised Filing Requirements Under Part 33 of the Commission's Regulations*, Order No. 642, FERC Stats. & Regs. ¶ 31,111 (2000) ("Order No. 642"); *Transactions Subject to FPA Section 203*, Order No. 669, FERC Stats. & Regs. ¶ 31,200 (2005) ("Order No. 669"), *order on reh'g*, Order No. 669-A, FERC Stats. & Regs. ¶ 31,214 ("Order No. 669-A"), *order on reh'g*, Order No. 669-B, FERC Stats. & Regs. ¶31,225 (2006) ("Order No. 669-B"); *Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement*, Order No. 592, 77 FERC ¶61,263 (*mimeo*), FERC Stats. & Regs. ¶ 31,044 (1996), *reconsideration denied*, Order No. 592-A, 79 FERC ¶61,321 (1997) ("Merger Policy Statement"); *FPA Section 203 Supplemental Policy Statement*, FERC Stats. & Regs. ¶ 31,253 (2007).

relevant markets based on actual operational data related to the participants and the markets in which they operate. Evaluated in this manner, the substitutability or lack of substitutability among supply options in a market is made transparent, along with the relevant market(s), and the relative importance of the merging firms within the market(s). It is on this basis that the use of prescribed formulas regarding market shares, residual suppliers and concentration ratios, as well as other metrics, can be useful tools for evaluating the effects of a proposed merger.

In the IMM analysis, the definition of the relevant market is based on the actual substitutability among available, relevant resources which in turn is based on the physical facts of the system and how the PJM markets defined the substitutability among available resources in the relevant markets over the analysis period. Rather than limit its analysis to a predefined range of load and price levels, the IMM has analyzed every actual relevant market defined by a constraint and the system software. The relevant energy markets in this analysis are those local energy markets created by transmission constraints within the broader PJM market that occurred for one hundred or more hours in the 2012-2013 planning year. The relevant ancillary services markets are those defined by the actual operation of PJM markets over the October 1, 2012 through September 30, ~~-~~2013 period~~planning year~~. The relevant capacity markets are those that resulted from the actual operation of the markets for the 2015/2016 and 2016/2017 delivery years.

The IMM analysis of the relevant markets reflects the information available based on the actual operation of the PJM wholesale power markets, rather than approximations of seasonal geographic markets that ignore local transmission constraints, distribution factors and relative dispatch costs. The information used to prepare the analysis included in this report is highly confidential and market sensitive as it relates to specific market participants.[4]

The IMM analysis relies on what FERC terms economic capacity, or total capacity without netting of load obligations, also termed gross position. Net positions would be calculated by subtracting the load obligation from the supply of the relevant product for all participants that have both an obligation to purchase a product or to sell a product at a defined price and the ability to supply a product. Such participants, in this analysis, would be primarily integrated utility companies that have not yet been exposed to significant retail competition and that therefore retain most of their native load. A net position analysis would show the market results when the integrated utility companies retain their dominant position in the market. A complete net position analysis would also have to account for all financial positions of the respective companies which affect

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4 See OATT Attachment M–Appendix § I.

When RPM clears as a single market, total RTO supply and demand determine the clearing price and all resources receive the clearing price. The market definition is clear. When an LDA within the RTO clears as a separate market, the incremental locational supply available to meet the locational demand determines the clearing price for the LDA. All capacity resources in the LDA receive the clearing price, regardless of whether the capacity resources are incremental.

~~w~~When there are multiple LDAs that clear as separate markets and the LDAs are not overlapping, the logic is exactly the same for each LDA separately and its relationship to the rest of RTO. When the LDAs are nested, one within another, the analysis becomes more complex. For example, EMAAC is entirely within MAAC, which is entirely within the RTO. The EMAAC locational price is determined by the incremental locational supply available to meet the locational demand within EMAAC. The MAAC price in this case is analogous to the RTO price in the case of a single LDA. The MAAC price is determined by all the MAAC incremental supply (defined with respect to the RTO market) that is not incremental in EMAAC. Even though MAAC includes more capacity resources than EMAAC, the MAAC clearing price may result from fewer MW of incremental supply than the EMAAC price and may apply to fewer MW of rest of MAAC supply than the EMAAC price. The MAAC clearing price in this case could also be referred to as the rest of MAAC price, analogous to the rest of RTO price. The rest of RTO clearing price in this case is determined by all the supply that is not incremental in MAAC, including EMAAC.

Total Market Analysis

HHI Analysis

Table 0-7 shows pre and post merger HHIs for the 2015/2016 and 2016/2017 RPM Base Residual Auctions, including all constrained LDAs for each BRA.[38] The HHIs in Table 0-7 measure concentration of ownership for all capacity in the identified LDAs. This metric measures the incentive to exercise market power rather than the ability to exercise market power in the constrained LDAs. Table 0-7 also shows the change in HHI and whether the change was between 50 and 100 points, 100 to 200 points, 200 to 300 points or exceeded 300 points. As a result of the location of the capacity resources of the two companies there was a change in HHI only for the RTO market and that increase was less than 50 points.

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[38] For the HHI analysis the sell offers were adjusted to include the withdrawn deactivations of Avon Lake 7, Avon Lake 9, New Castle 3, New Castle 4, New Castle 5, New Castle Diesel and Gilbert 8 units; to reflect the fact that EME no longer owns the Homer City plant; and to remove sell offers for resources that are no longer capacity resources as of December 2013.

Table 0-8 Pre and post merger TPS analysis

RPM Auction	RPM Market	Pre Merger RSI_3	Post Merger RSI_3	Change in RSI_3	Percent Change
2015/2016 Base Residual Auction	RTO	0.546	0.529	(0.016)	(2.9%)
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	ATSI	0.000	0.000	0.000	0.0%
2016/2017 Base Residual Auction	RTO	0.597	0.577	(0.021)	(3.5%)
	MAAC	0.380	0.380	0.000	0.0%
	PSEG	0.000	0.000	0.000	0.0%
	ATSI	0.000	0.000	0.000	0.0%

Table 0-9 Pre and post merger TPS scores by cleared LDA by RPM Base Residual Auction: NRG, Edison Mission Energy and Combined

		Pre Merger RSI_3		Post Merger RSI_3
RPM Auction	RPM Market	NRG	Edison Mission	Merged Company
2015/2016 Base Residual Auction	RTO	0.553	0.602	0.529
	MAAC	0.668		0.668
	ATSI			
2016/2017 Base Residual Auction	RTO	0.597	0.649	0.577
	MAAC	0.405		0.405
	PSEG			
	ATSI			

Regulation Market Results

The analysis of the impact of the merger on the Regulation Market examines the Regulation Market hours when either Edison Mission Energy or NRG supplied and cleared regulation MW in the period from October 1, 2012 through September 30, 2013.[40] These are the relevant regulation markets. A market hour exists each time that PJM dispatch software runs and clears the regulation market. The IMM's calculated HHI levels on a pre merger and a post merger basis for each market hour. The analysis indicated that the proposed merger raises significant market power concerns in the regulation market.

Table 0-10 shows pre and post merger HHIs for the relevant regulation market for October 2012 through September 2013. The table shows that, overall, the regulation market affected by NRG and Edison Mission Energy resources is highly concentrated. Pre-merger terms, 53.1 percent of the market hours affected by NRG and Edison Mission Energy resources had an HHI of 1800 or more, 37.6 percent had an HHI of 2000 or more and 12.9 percent of the market hours had an HHI of 2500 or more. Post merger, 55.6

40 This period was chosen to align with the significant changes to the Regulation Market which were implemented on October 1, 2012.