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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, LLC) Docket No. ER04-539-001

REPLY OF
PJM INTERCONNECTION, LLC

PJM Interconnection, LLC ("PJM"), pursuant to Rule 213 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213, hereby submits its reply to the answers to PJM's April 23, 2004 request for rehearing in this case.[1] As shown in PJM's request for rehearing, the Commission should reconsider its March 24, 2004 order in this proceeding[2] and permit temporary mitigation of market power in the Northern Illinois Control Area ("NICA") capacity market. No party seriously rebuts the evidence that the structure of the NICA capacity market will permit non-competitive behavior, and PJM has presented a well-tailored mitigation proposal, which can be developed further, if the Commission desires, through a compliance filing.

The Commission should grant PJM's request for rehearing. Pursuant to the market rules approved by the Commission,[3] NICA will have a separate capacity market

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1 While the Commission's rules generally do not permit replies to answers (see 18 C.F.R. § 385.213(a)(2)), the Commission has made exceptions "where an answer clarifies the issues or assists in creating a complete record." Idaho Power Co., 95 FERC ¶ 61,482, 62,717 (2001); see also Cambridge Elec. Light Co., 95 FERC ¶ 61,162, 61,523 (2001). Here, the Commission clearly desires a complete record on this important market mitigation issue, as shown by its order inviting responses to PJM's request for rehearing. PJM's reply clarifies certain issues raised by the responses, provides a more complete record to assist the Commission in reaching its decision, and therefore should be permitted.

2 PJM Interconnection, LLC, 106 FERC ¶ 61,277 (2004) ("March 24 Order").

3 PJM Interconnection, LLC, 106 FERC ¶ 61,253 PP 45-50 (2004).

for over eleven more months, through May 31, 2005, even if American Electric Power Company joins PJM in October. PJM will administer 44 more capacity auctions during this period. As the evidence indicates that the NICA market is structurally non-competitive, the Commission should establish mitigation to protect consumers from the exercise of market power. PJM's proposed mitigation measures can be implemented promptly and, contrary to opponent's claims, do not depend on the discretion of the PJM market monitoring unit ("MMU"). The only role for the MMU is to confirm a seller's documentation that its capacity costs exceed \$30/MW-day, in line with the previously detailed FERC accounting cost components. Assigning this role to the MMU should expedite that determination. However, if the Commission prefers procedures in which the Commission makes this determination, or wishes the cost components to be stated in the PJM Operating Agreement, such implementation details can be established in a compliance filing while maintaining a prompt effective date for mitigation.

I. BACKGROUND

On February 5, 2004, PJM filed revisions to the PJM Open Access Transmission Tariff ("PJM Tariff") and the Amended and Restated Operating Agreement of PJM Interconnection, LLC ("Operating Agreement") to establish market power mitigation measures for the NICA capacity market, to be effective for the twelve-month period following Commonwealth Edison Company's ("ComEd") integration into PJM during which there is a separate NICA capacity construct and market.

Based on concerns about the non-competitive structure of the NICA capacity market, PJM proposed that capacity offers in NICA would be capped at \$30 per MW-day, plus any additional amounts shown to be needed to compensate the seller of capacity for its opportunity cost. PJM proposed to increase the cap to $160 per MW-day under scarcity conditions, as defined in the proposal.

In its March 24 Order, the Commission rejected PJM's proposed NICA capacity market mitigation measures. It concluded that PJM had "not adequately considered all potential sources of capacity" in determining that the NICA capacity market was highly concentrated.[4] The Commission also stated that the proposed rules were not "sufficiently clear with regard to the capacity offer cap, specifically as to any additional amounts added to the initial $30 per megawatt day cap" and that "such a mitigation scheme accords the market monitor excessive discretion in determining the level of individual offer caps."[5]

In its April 23, 2004 request for rehearing, PJM asked the Commission to reverse its conclusions on concentration in the NICA capacity market and on the capacity offer price cap. In PJM's request for rehearing, the MMU supported its conclusion on capacity market concentration with an analysis of the NICA capacity market using the screens described in the Commission's Market Power Policy Order,[6] issued after the original filing in this docket, and with the results of the three NICA capacity auctions conducted after the March 24 order.

As shown in the request for rehearing and the attached supporting declaration of the manager of PJM's MMU, Joseph E. Bowring, ("Bowring Dec.") applying the Commission's market share analysis to the NICA capacity market demonstrated that one

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4 March 24 Order at P 37.

5 Id. at P 35.

6 AEP Power Mktg., Inc., 107 FERC ¶ 61,018 (2004) ("Market Power Policy Order").

generation supplier in NICA has more than a 20 percent market share,[7] indicating that the stand-alone NICA capacity market has a non-competitive structure. The MMU's analysis directly addressed the data concerns identified in the March 24 Order, by explicitly accounting for imports, native load obligations, and generation owners' control of others' generation through power purchase agreements ("PPAs").[8]

PJM also reviewed the three NICA capacity auctions conducted before the request for rehearing was filed. As summarized in the rehearing request and accompanying declaration, these three capacity auctions were not characterized by competitive behavior, demonstrating little diversity of supply and low participation by generators. One or more suppliers were pivotal in all three auctions. The Commission's market share screens were exceeded in all three auctions, and there was no evidence of any imports competing in any of the auctions. The actual experience with these auctions therefore reinforced the need for market mitigation.

To address the Commission's concerns about market monitor discretion over generator compensation above the $30 per MW-day cap, PJM provided a list of the categories of costs (based on the Commission's Uniform System of Accounts) a market participant could use to document that its total costs for a particular unit exceed $30 per MW-day. PJM advised that, if the Commission granted rehearing, PJM would incorporate such cost categories in its manuals or, if the Commission preferred, submit the cost list in a compliance filing as an amendment to the market rules in the PJM tariff.

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7 PJM Request for Rehearing, Docket No. ER04-539-000 (April 23, 2004) Exh. A, Bowring Dec. at PP 14-17.

8 Id. at P 1.

The Illinois Commerce Commission also sought rehearing of the March 24 Order, "urg[ing] the Commission to either reinstate the rejected capacity market power mitigation measures or direct PJM to submit replacement capacity market power mitigation measures."[9]

On May 5, 2004, the Commission issued an order allowing parties until May 26, 2004 to respond to PJM's request for rehearing.[10] The EME Companies ("EME"), the NRG Companies ("NRG"), Duke Energy North America, LLC, ("Duke"), and the Electric Power Supply Association ("EPSA") filed answers in opposition to PJM's request for rehearing. Peoples Energy Service Corp., an alternative retail electric supplier in Illinois, filed an answer encouraging the Commission to grant PJM's request for rehearing, stating that "[t]he potential for market power abuse is real and should be addressed."[11]

II. REPLY

A. EME's Revised Information About Some of its Generation Units Does Not Change the Conclusion that the NICA Capacity Market May be Characterized by Structural Market Power.

The MMU's April 23 Declaration found that one seller failed the wholesale market share screen established by the Market Power Policy Order. No intervenors contest this conclusion. However, one intervenor presents information that certain of its units have been taken out of service or are in suspended operation.

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9 Request for Rehearing and Clarification of the Illinois Commerce Commission, Docket No. ER04-359-000 (April 21, 2004) at 14.

10 PJM Interconnection, LLC, 107 FERC ¶ 61,105 (2004).

11 Comment of Peoples Energy Services Corp., Docket No. ER04-539-001 (May 26, 2004) at 1.

As explained in the attached declaration of the market monitor, those units were included in the MMU's analysis based on the seller's formal entries in PJM's eDART system indicating that the units would return to service in June 2004. Nonetheless, based on the intervenor's representations in its latest pleading, the units have been removed from the MMU's updated analysis described in the attached declaration.

The MMU also updated its analysis to reflect the actual experience with imports in the capacity auctions conducted to date. As indicated in the April 23 Declaration, there were no imports offered into the three auctions conducted in April. Further experience has reinforced that capacity imports are not likely to discipline prices in this market. While no capacity imports were bid into any of the subsequent auctions, information reported to PJM shows that, as of June 1, 2004, there were bilateral agreements for only a limited amount of capacity imports, and that those were more than offset by capacity exports from NICA.

Based on this actual experience, the MMU re-ran the market power screens under the Market Power Policy Order, to test for sensitivity to the level of imports. The updated analysis also accounted for EME's revised information regarding unit availability. The wholesale market share results still indicated the market share screen is failed under all import scenarios.

The updated pivotal suppler analysis shows that, if 4700 MW of imports is assumed, then no generation owner is pivotal. However, the import sensitivity anlysis shows that one market participant is pivotal in the capacity market at more limited import levels that more closely relate to actual experience. This is consistent with experience in the capacity auctions to date, in which there was no competition from imports and one supplier was pivotal.

B. The Finding that One or More Sellers has Market Power Requires Mitigation for the Market, Rather than Mitigation Only for Those Sellers.

NRG, Duke, and EPSA do not dispute that one or more sellers failed the screens under the Market Power Policy Order, but contend that this requires mitigation only of those sellers, rather than mitigation for all sellers in the market. They ignore the fundamental problem that the separate NICA capacity market has a non-competitive structure, which presents opportunities for gaming or abuse by any seller. While the screens described in the Market Power Policy Order are used there for the purpose of deciding whether an individual seller should be allowed market-based rates, these are the same tools and standards generally used by economists (and the Commission) to determine whether a market is competitive. For example, when the Commission decided whether to allow market-based rates generally for the PJM regional energy market, it considered evidence of the market's concentration based on an HHI standard. Here, there is ample evidence, based on both the Commission's screens and the experience in the capacity auctions to date, that the separate NICA capacity market is structurally non-competitive. As discussed below, there are multiple, significant exceedances of the screens under realistic scenarios, and the levels of market concentration seen in the capacity auctions greatly exceed any generally accepted standard for competition.

As Mr. Bowring explains in his declaration, where a market's structure is not competitive, it is not enough to impose constraints only on one or two dominant players. Organized markets, like the PJM market, include a variety of interactions among market participants. The mitigation solely of the one or two suppliers that are dominant in a market would incent the exercise of market power via gaming and other behaviors. Mitigation of single market participants could create incentives for large and small participants to cooperate either tacitly or explicitly to exercise market power and could thus create unanticipated consequences for the markets.

Mr. Bowring cites examples in which application of mitigation only to one or two generation owners in a market would create the incentive for the mitigated generation owner to enter into bilateral arrangements, under which a non-mitigated participant controlled bidding of pivotal resources, to circumvent mitigation. The non-mitigated participant could offer the units at a non-mitigated price and set the market price. A large generation owner could make non-mitigated generation owners pivotal by withholding generation, enabling the non-mitigated generation owner to set prices through its offers, which would benefit the mitigated generation owner. Therefore, contrary to the intervenors' arguments, the structural problems in this market require mitigation on all sellers.

This is no different from mitigation applied elsewhere in PJM. As Mr. Bowring explains, before market-based pricing was approved for the PJM energy market, the offers of all participants were cost-based. The Commission did not distinguish among individual generation owners that otherwise had market-based rate authority and those that did not have market-based rate authority. Rather, the offers of all market participants were capped until the Commission determined that the PJM markets were structurally competitive. Moreover, even when the PJM transmission owners filed in 1997 for market-based rates in PJM, they recognized that market power could be exercised in load pockets and therefore provided for mitigation of all sellers in load pockets. The PJM local market power mitigation measures, included in that initial filing and approved by the Commission, do not distinguish among generation owners in load pockets. The behavioral remedy is applied whenever a generation owner has the ability to exercise market power regardless of whether the generation owner is the only owner in the load pocket (a 100 percent market share) or whether the load pocket has one generation owner with a 90 percent share and one with a 10 percent share. In PJM, load pockets are uniformly characterized by structural market power but can, in some instances, include generation owners that would pass the market power tests in the Market Power Policy Order. Such generation owners are, nonetheless, at times in a position to exercise market power but for the local market power mitigation rules.

C. The Clearing Prices Resulting from the Capacity Auctions Do Not Show that the NICA Capacity Market is Competitive.

Notwithstanding, as shown above, that the three capacity auctions conducted in April showed low participation, high concentration, and little diversity, EME argues that the clearing prices resulting from those auctions negate concerns about market power. However, for a market with the structural problems of the NICA capacity market, the Commission should not trust to chance. The separate NICA capcity market will be in place for eleven more months, with forty-four more auctions. It is possible that participants might not take advantage of the structural infirmities in the market, but it would be economically rational for them to do so, especially if the Commission denies rehearing, and the threat of a $30/MW-day offer cap is perceived to diminish. Given the evidence concerning the structure of this market, the Commission should impose mitigation.

Notwithstanding the structural market power in the separate NICA capacity market, EME's consultant Mr. Shanker argues against market mitigation rules, suggesting instead that "it is appropriate for the MMU to have well defined recourse to protect market participants (both supply and load) from the exercise of market power when warranted by specific events." (EME Response, Docket No. ER04-539-001 (May 26, 2004) Exh. A, at 10 n.21). However, the MMU's authority to address specific participant actions (as defined in the Market Monitoring Plan) is not sufficient to address the issues in the NICA capacity market on an ex post basis. The MMU could report on any exercise of market power, but has no enforcement authority and no ability to impose remedies. The approach proposed by Mr. Shanker is an ex post approach to market power that is clearly at odds with the Commission's recent statements regarding the appropriateness of clear, ex ante rules governing market behavior. See, e.g., Investigation of Terms and Conditions of Public Utility Market-Based Rate Authorizations, 103 FERC ¶ 61,349 (2003); ISO New England, Inc., 104 FERC ¶ 61,039 (2003). The MMU is proposing a clear, implementable set of ex ante rules governing the exercise of market power precisely to avoid ex post enforcement and the market uncertainty associated with ex post enforcement.

D. EME's Criticisms of the $30/MW-day Offer Cap, and its Alternative Calculation of a $54/MW-day Cap, Should be Rejected.

EME, through its consultant Mr. Shanker, criticizes the proposed $30/MW-day offer cap. EME argues that, if mitigation is required, the offer cap should be $54/MW-day, based on Mr. Shanker's calculations.

However, Mr. Shanker fails to address the central issue, i.e., with or without market power, how is the competitive price in the NICA capacity market defined?[12] For

[12] Mr. Shanker's related criticisms of the existing PJM capacity market construct are misplaced. The only questions in this proceeding are whether the separate NICA capacity market is non-competitive and, if so, what temporary mitigation should

a capacity market with a term of one year, as established for NICA, the competitive price is the avoidable cost associated with maintaining a unit as a capacity resource for one year, i.e. the marginal cost of capacity. In a competitive market, this is the price that a rational seller of capacity will offer the market. This is supported by the actual behaviors of sellers in both the PJM MidAtlantic and NICA capacity markets. As Mr. Bowring states in his declaration, sellers make substantial amounts of capacity available in both the pre-existing PJM and NICA capacity markets at less than $30 per MW-day.[13] Mr. Bowring also relates that the MMU has had discussions with participants about supporting higher capacity market offers based on units with going-forward costs higher than $30 per MW-day.

As explained in the MMU's Declaration, the $30 per MW-day proposed offer cap is based on detailed data on the annual avoidable costs associated with maintaining a unit as a capacity resource. The April 23 Declaration relied on cost data from actual recently constructed combustion turbines, and was itemized in detail in the April 23 Declaration. EME argues that this data is insufficient because it is not based on older plants. To the contrary, current costs to build a new competing unit are commonly used for a cost-based mitigation measure. Nonetheless, to address this criticism and confirm the result, the market monitor includes with his latest declaration corroborating cost data for currently

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be in place until May 31, 2005. Larger questions about the future capacity construct for the entire PJM region will be resolved elsewhere.

13 When comparing prices in NICA and PJM MidAtlantic it is important to remember that the NICA market is an installed capacity market while the PJM MidAtlantic market is an unforced capacity market. The difference is that unforced capacity accounts for the forced outage rates of generating units. It is necessary to multiply PJM MidAtlantic UCAP prices by .94 in order to be comparable to the ICAP prices in NICA.

operating combustion turbines in PJM and in NICA, ranging in age from 2 to 36 years. The MMU obtained this data from publicly available sources, a commercial data source, and individual operating companies in PJM and NICA. As the market monitor states in his declaration, the data indicate a cost for older units of $22.84 to $28.74/MW-day, and therefore support that $30 per MW-day is a conservative estimate of the avoidable annual costs associated with maintaining a capacity resource.

Mr. Shanker asserts that the $30 going forward costs do not include property taxes or insurance. That is partially correct. Property taxes are not an avoidable cost because property taxes would continue to be incurred if a unit were shut down for a year. Mr. Shanker nowhere asserts that property taxes are avoidable. Therefore, property taxes were excluded from the $30 estimate because they do not meet the definition of annual avoidable cost. Mr. Shanker's calculations based on a study from the California Energy Commission ("CEC") also exclude property taxes, as do most of the studies he cites. By contrast, avoidable insurance costs are properly included in going-forward costs, and the PJM market monitor included them in his calculation of $30/MW-day. For example, significant discounts are available for boiler and machinery insurance and general liability insurance if a unit is to shut down for a year. Those discounts reflect avoidable insurance costs that are appropriately includable in the annual avoidable costs.

Rather than rely on data from any of EME's units, Mr. Shanker uses a range of studies, with limited analysis of cost components, in an effort to support his alternative proposed offer cap of $54.80 per MW-day. However, these studies do not support his result. The CEC study, on which he relies for the $54.80 estimate, includes levelized cost estimates for several generic central-station electricity generation technologies. (EME Response, Att. RJS-1 at 1) These cost estimates include all fixed and variable costs associated with building the referenced units and do not distinguish between avoidable and unavoidable costs. The costs are presented on a levelized basis which is equivalent to front-loading the costs when compared to actual current costs. Levelized costs are not a seller's actual avoidable costs from not operating for a year. Mr. Shanker also selects various cost components from the CEC's levelized cost of service without considering whether these costs are annual avoidable costs. For example, he includes all insurance costs, rather than only the portion of insurance costs that are avoidable if the unit does not operate for a year.[14] As shown on Table CAP5 (Tab 5) by making only two adjustments to Mr. Shanker's calculation, i.e., using current dollars instead of a levelized cost of service, and replacing all insurance costs with annual avoidable insurance costs, the result is $30.16 per MW-day, which supports PJM's proposed offer cap.

Notwithstanding Mr. Shanker's criticisms, the $30 per MW-day going forward cost is conservatively high, because it is based on the costs of a combustion turbine with the assumption that there are zero net revenues derived from the energy market to offset these costs. As Mr. Bowring explains, in actual operations, combustion turbines receive net revenues from the energy market. For example, the PJM Interconnection State of the Market Report for 2003 estimated the net revenue for a new CT in PJM as $15,380 per MW-year in 2003 and $36,169 per MW-year on average from 1999 through 2003. This is equivalent to $42 per MW-day and $99 per MW-day, respectively. The MMU reviews actual net revenues for operating CTs in PJM, and attests that in 2003 such revenues were consistent with the above analysis.

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14 Mr. Shanker also states that he includes property taxes, but they are not reflected in his calculation. Nor should they be, since property taxes cannot be avoided by suspending operations for a year, as discussed above.

The $30 calculation also is conservative because it does not subtract the significant costs of taking a unit out of service for a year. If the alternatives considered by a seller are operating the unit for a year or shutting the unit down for a year, the incremental costs associated with shutting the unit down for a year should be considered. While that additional cost is not being considered explicitly here, it is worth noting, as it makes clear that the $30 per MW-day cost calculation is conservative. In this regard, EME's affiant Mr. Gorney acknowledges the "considerable" costs of returning to service units that have suspended operations.

E. NRG's Contention that Temporary Mitigation Measures in NICA Will Force Economic Retirements and Jeopardize Satisfaction of Reserve Requirements is Not Credible.

NRG contends that the $30/MW-day offer cap is too low and speculates that it would drive NICA units into economic retirement as early as this summer.[15] NRG cites a North American Electric Reliability Council ("NERC") assessment for the claim that the projected July 2004 reserve margin in MAIN (the reliability region that includes NICA) is significantly below MAIN's recommended 14.12% reserve margin. However, NRG mischaracterizes the results of the MAIN summer assessment. The referenced MAIN summer assessment predated the integration of NICA into PJM and does not support the

15 NRG also proposes changes to PJM's rules for all of its capacity markets, including NICA, to adopt demand-curve pricing. PJM is currently considering alternatives to the existing PJM capacity rules, but the present NICA mitigation proposal has a far narrower objective, i.e., to address market power concerns in the separate NICA capacity market that exhibits relatively few sellers and relatively high concentration, for the limited period that such market is in place. Where there is a current need for mitigation, the remedy should not await development of complex and controversial new pricing approaches.

NRG claim. In fact, the MAIN summer assessment (attached at Tab 9) states that the summer reserve margin could be as low as 8.7 percent and as high as 29.7 percent.[16]

The principal concern cited in the MAIN assessment was that some load did not have firm capacity contracts and that available capacity was therefore not committed to serving load in MAIN. Integration into PJM has addressed this issue for NICA because load-serving entities must purchase capacity resources equal to 115% of their summer peak loads, and that requirement is being satisfied in NICA on an ongoing basis.

Moreover, NRG's speculation that the short-term imposition of necessary market power mitigation in NICA will force a wave of economic retirements in MAIN is not credible. The offer cap will apply only in NICA, and only until May 31, 2005. A generator deciding whether to retire its units on economic grounds based on an 11-month mitigation measure must take into account the costs of returning its unit to operation after the mitigation expires. In addition, the clearing prices recorded in the NICA auctions to date (as well as many of the offer prices) rebut the notion that generators cannot operate in NICA with a capacity revenue stream based on $30/MW-day.

F. The Proposed Procedures for Compensation Above $30/MW-day Eliminate Concerns About Market Monitor Discretion.

PJM's initial NICA capacity market mitigation proposal allowed sellers the opportunity to demonstrate that their cost of capacity for specific units is greater than

16 The MAIN assessment states: "If only capacity that is planned and committed to serving firm load within MAIN is considered, the reserve margin would be 8.7%, which is below MAIN's recommended 14.12% reserve margin. However, MAIN also has 11,412 MW of operable uncommitted generation potentially available to serve load this summer. It is uncertain how mjch of this uncommitted generation will be available to serve MAIN load this summer. The reserve margin considering all operable generation in MAIN (committed within MAIN plus uncommitted) is forecasted to be 29.7% which is above MAIN's 14.12% reserve margin recommendation for the upcoming summer."

$30/MW-day. In PJM's request for rehearing, PJM refined its proposal to address concerns about MMU discretion. Specifically, Tab K to the April 23 Declaration included a complete list of the categories of costs (based on the Commission's Uniform System of Accounts) that PJM proposed should qualify for the demonstration of annual avoidable costs in excess of $30/MW-day. PJM offered, if the Commission felt it necessary, to include this definition of qualifying cost categories in the filed PJM market rules, making them subject to Commission approval.

Duke argues that this process still reserves too much discretion to the MMU. However, the considerations to which Duke objects are not items of MMU discretion, but rather findings and conclusions that PJM is asking the Commission to adopt and fix. Once the Commission accepts that mitigation is required, that actual annual avoidable costs are properly compensated for sellers subject to mitigation, and that PJM has put forth an appropriate definition and itemization of such costs in its request for rehearing, all that is left for the MMU is to verify that a seller has documented such costs.

Allowing the MMU to perform that verification should be the most timely and efficient approach. However, the Commission also can establish procedures for recourse to the Commission, or can reserve to itself the determination of whether a seller is entitled to compensation above the $30 cap.

III. REQUEST FOR PRIVILEGED TREATMENT

Pursuant to 18 C.F.R. § 388.112, PJM respectfully requests privileged treatment of portions of the attached Declaration of Joseph E. Bowring, Manager of the PJM Market Monitoring Unit and the attachments thereto. This information is exempt from mandatory public disclosure requirements, as it contains privileged or confidential commercial and financial information of the PJM members. See 5 U.S.C. § 552(b)(2); 18

U.S.C. § 1905, 18 C.F.R. §§ 388.107(d), 388.112; and Operating Agreement § 18.17. Disclosure of the information contained in the declaration and the attachments would reveal privileged or confidential commercial and financial information of PJM members and would cause harm to the competitive positions of PJM members and also is prohibited by the Operating Agreement.

Pursuant to 18 C.F.R. § 388.112(b)(iv), the person to be contacted regarding this request for privileged treatment is:

Barry S. Spector
Paul M. Flynn
Wright & Talisman, P.C.
1200 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 393-1200
(202) 393-1240 – fax

IV. CONCLUSION

For the reasons stated above, the Commission should grant PJM's request for rehearing.

Respectfully submitted,

Barry S. Spector
Paul M. Flynn
Wright & Talisman, P.C.
1200 G Street, N.W.
Suite 600
Washington, D.C. 20005
(202) 393-1200
(202) 393-1240 (fax)

Craig Glazer
Vice President - Government Policy
PJM Interconnection, L.L.C.
1200 G Street, N.W
Suite 600
Washington, D.C. 20005
(202) 393-7756
(202) 393-7741 (fax)

Vincent P. Duane
Deputy General Counsel
PJM Interconnection, LLC
955 Jefferson Avenue
Norristown, PA 19403
(610) 666 4367 (phone)
(610) 666 4281 (fax)

Attorneys for
PJM Interconnection, LLC

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INFORMATION HAS BEEN REMOVED FOR PRIVILEGED TREATMENT

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)	**Docket No. ER04-539-001**

DECLARATION OF JOSEPH E. BOWRING

I, Joseph E. Bowring, Manager of the PJM Interconnection, L.L.C. Market Monitoring Unit depose and say as follows:

Introduction

1. In its Order on Market Mitigation Mechanisms[1], the Commission raised questions about the factors considered in the market power analysis proposed by the PJM Market Monitor for the capacity market in NICA. I filed a Declaration in support of PJM's April 23, 2004 request for rehearing of that Order ("April 23 Declaration") which addressed all of the questions raised by the Commission, by following the methods specified in the Market Power Policy Order[2], issued after the Order on Market Mitigation Mechanisms. The methods defined in that Order address many of the same issues raised in the Order on Market Mitigation Mechanisms and provide a clearly specified method for addressing those issues.[3] PJM applied the screens defined in the Order and found that **[Redacted]** fails the market share screen for market power. Based on the additional analysis performed in response to intervenors comments, that continues to be the case. The additional analysis performed in response to intervenors comments shows that **[Redacted]** also fails the pivotal supplier screen for market power with imports up to 700 MW. Moreover, the actual results of the NICA capacity market auctions support the conclusion that the NICA capacity market is not competitive and that market participants have the ability to exercise market power.[4] [5]

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1 PJM Interconnection, L.L.C., 106 FERC ¶ 61,277 (2004) ("Order on Market Mitigation Mechanisms.")

2 AEP Power Marketing, Inc. 107 FERC ¶ 61,018 (2004) ("Market Power Policy Order").

3 The analysis here is consistent with that provided earlier, but the analysis here follows the clear guidelines established in the Commission's Market Power Policy Order.

4 **[Redacted]**

5 **[Redacted]**

2. In summary I find that market participants in the NICA capacity market have the ability to exercise market power. In different terms, the NICA capacity market is structurally non-competitive. Consistent with the Market Power Policy Order, the focus in the analysis is on the structure of the market and the associated ability to exercise market power rather than on actual behaviors. The structure of the market permits sellers to exercise market power and requires that the potential for market participants to exercise market power be addressed ex ante. The conclusion that the structure of the capacity market in NICA is not competitive has not been contested with any analysis of the market. In order to ensure that market power is not exercised in the remaining NICA capacity market auctions, mitigation is necessary to ensure a competitive outcome in the capacity markets. The competitive price in the capacity auctions is the annual avoidable cost, which is the incremental cost of capacity in a one year capacity market. No intervenor contested that the annual avoidable cost is the competitive price in a one year capacity auction. In fact, the annual avoidable cost, as presented, is a very conservative estimate of the competitive price as it does not account for significant offsetting factors.

3. In view of the results of the market power analysis including both the market power screens and the actual results of the initial capacity market auctions, I believe that the Commission should grant rehearing, impose market power mitigation and, as necessary, require PJM to make a compliance filing that specifies any details the Commission determines should not be left to the PJM Manuals or the Market Monitor's discretion.

4. The presence of market power in the NICA capacity market remains a significant concern notwithstanding the fact that some auctions have already been run. Under the rules approved by the Commission, this market will remain in place through May 31, 2005. To support this market, PJM plans to run an additional 32 NICA capacity market auctions in 2004 (Table CAP1) and an estimated 12 more in 2005.[6] The requested mitigation will not apply after May 31, 2005 because the separate capacity construct for NICA will not continue beyond that date.

5. In this Declaration I respond to the specific comments on PJM's request for rehearing. No party substantively addressed the details of the market power analysis for the NICA capacity market. Several parties suggested that the proposed mitigation is difficult to implement and provides too much discretion to the MMU. Several parties argued that the $30 offer cap is too low. Some parties suggested other approaches to market power mitigation.

Market Power Analysis for the NICA Capacity Market

6. The NICA capacity market does not satisfy the market share screen for competitiveness under the Market Power Policy Order. **[Redacted]** did not contest PJM's conclusion that the results of the market power analysis show that **[Redacted]**

6 Tables (CAP1 through CAP5) are organized with tabs at the end of the document. Supporting data is in subsequent tabs (Tab 6 through Tab 9).

has a capacity market share greater than 20 percent. Some commenters argue that this requires mitigation only of **[Redacted]**, rather than mitigation of all sellers in the market. This argument ignores the fundamental problem that the NICA capacity market has a non-competitive structure, which presents opportunities for gaming or abuse by any seller. While the screens described in the Market Power Policy Order are used for the specific purpose of deciding whether an individual seller should be allowed market-based rates, these are the same tools and standards used by economists (and the Commission) to determine whether a market is competitive. For example, when the Commission decided whether to allow market-based rates generally for the PJM regional energy market, it considered evidence of the market's concentration based on an HHI standard. There is substantial evidence, based on both the market power screens and the experience in the capacity auctions to date, that the NICA capacity market is structurally non-competitive. As discussed below, **[Redacted]** fails the pivotal supplier screen under the limited import scenario and fails the market share screen in every season. Moreover, the levels of market concentration actually observed in the capacity auctions exceed any generally accepted standard for competition. (CAP3.)

7. Where the structure of the market is not competitive, as is the case here, it is not adequate to mitigate only one or two dominant participants. Organized markets, like the PJM market, include a variety of interactions among market participants. The mitigation solely of the one or two suppliers that are dominant in a market would incent the exercise of market power via gaming and other behaviors. Mitigation of single market participants could create incentives for large and small participants to cooperate either tacitly or explicitly to exercise market power and could thus create unanticipated consequences for the markets. For example, the application of mitigation only to one or two generation owners in a market would create the incentive for the mitigated generation owner to enter into bilateral arrangements, under which a non-mitigated participant controlled bidding of pivotal resources, to circumvent mitigation. The non-mitigated participant could offer the units in at a non-mitigated price and set the market price. A large generation owner could make non-mitigated generation owners pivotal by withholding generation, enabling the non-mitigated generation owner to set prices through its offers, which would benefit the mitigated generation owner. While these are simple illustrations of behaviors that could occur absent mitigation of all market participants in structurally non-competitive markets, it does not make sense to create incentives to engage in new forms of non-competitive behavior. There are potential negative consequences from the mitigation of single generation owners while there is no asserted harm from the application of the mitigation rules to all participants.

8. Prior to the introduction of market-based pricing in PJM markets, the offers of all participants were cost-based. The Commission did not distinguish among individual generation owners that otherwise had market-based rate authority and those that did not have market-based rate authority. Rather, the offers of all market participants were capped until the Commission determined that the PJM markets were structurally competitive. The PJM companies filed jointly in 1997 for market-based rates to create the current, security-constrained, market-based PJM market model. However, the

filing by the PJM companies recognized that market power could be exercised in load pockets and therefore provided for mitigation of all sellers in load pockets. The PJM local market power mitigation measures, included in that initial filing and approved by the Commission, do not distinguish among generation owners in load pockets. The behavioral remedy is applied whenever a generation owner has the ability to exercise market power regardless of whether the generation owner is the only owner in the load pocket (a 100 percent market share) or whether the load pocket has one generation owner with a 90 percent share and one with a 10 percent share. In PJM, load pockets are uniformly characterized by structural market power but can, in some instances, include generation owners that would pass the market power tests in the Market Power Policy Order. Such generation owners are, nonetheless, at times in a position to exercise market power but for the local market power mitigation rules.

9. In its answer to PJM's request for rehearing, EME commented that the market power analysis is flawed because it ascribes to EME several units that have been taken out of service. These units are Collins Unit 4, Collins Unit 5, Will County Unit 1, Will County Unit 2 and the Bloom peaker units. PJM included these units in the analysis reported in the April 23 Declaration based on the formal entries made by EME in PJM systems (eDART) indicating that the units are all on planned outages and are all due to return to service on June 13, 2004. Based on the representations of EME in its latest pleading, the units have been removed from the analyses reported in this Declaration.

Pivotal Supplier Screen

10. The pivotal supplier screen reasonably can be applied to any market. The PJM MMU has historically applied a pivotal supplier test to all PJM markets.[7] For the April 23 Declaration, I conducted a pivotal supplier screen using the method defined in the Market Power Policy Order and found that no generation owner is pivotal in the NICA capacity market for the period analyzed, assuming 4,700 MW of imports. For purposes of this Declaration, I have updated the pivotal supplier analysis to reflect the new information from EME about the status of certain of its units and to perform a sensitivity analysis incorporating actual experience about the role of imports in the NICA capacity market.

11. In the analysis conducted for the April 23 Declaration, I assumed that the 4,700 MW of import capability into NICA would be a source of competition in the capacity market. The actual experience with capacity market auctions in NICA makes clear that the assumption of competition from imports into the capacity market was unrealistic. While thirteen capacity market auctions were run for NICA prior to June 1, covering a variety of time periods up to a year in length, there were no imports offered into the capacity auctions. Although there were some capacity imports into NICA in the bilateral market, **[Redacted]**.

Information reported to PJM shows that, as of June 1, 2004, bilateral capacity exports from NICA were **[Redacted]** and bilateral

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7 See, for example, the MMU's annual State of the Market Report 2003.

capacity imports into NICA were **[Redacted]**, for a net bilateral capacity **[Redacted]** MW. Thus, there has been only very limited competition from imports in the capacity markets in NICA. While no entities were pivotal in the analysis assuming 4,700 MW of import capability, the results of the analysis reflecting sensitivity to import capability are quite different. The results of the analysis show that **[Redacted]** is pivotal with up to **[Redacted]** of net capacity imports. (CAP2.) Again, this result is supported by the actual market results reported below. **[Redacted]** was pivotal in every auction in which it participated and any capacity was sold. (CAP3.)[8]

Wholesale Market Share Analysis

12. For purposes of the April 23 Declaration, I conducted a wholesale market share analysis using uncommitted capacity, based on the principles and methodology prescribed by the Market Power Policy Order. That analysis showed that **[Redacted]** failed the market share screen, as its market share exceeded the 20 percent threshold specified in the Market Power Policy Order for each of the four seasons.

13. The wholesale market share analysis was redone, incorporating EME's new information regarding unit availabilities. The revised analysis shows that **[Redacted]** fails the market share screen, as its market share exceeds the 20 percent threshold specified in the Market Power Policy Order for each of the four seasons. The market share of **[Redacted]** exceeds the 20 percent level in each season with imports at the 4,700 level and also exceeds the 20 percent level in each season with imports up to **[Redacted]**, based on actual experience in NICA capacity markets. The maximum seasonal market share is **[Redacted]** percent in the 4,700 MW import case and **[Redacted]** percent in the **[Redacted]** import case. (Table CAP2.)[9] The **[Redacted]** import case is analogous to the delivered price test in this context because it conservatively accounts for the actual level of competition from first tier markets, based on actual market responses.

NICA Capacity Auction Results

14. As of June 1, 2004, PJM had run thirteen auctions for NICA capacity covering all or part of the period from June 1, 2004 through May 31, 2005. A total of 1,506.5 MW cleared in the 13 auctions for capacity for the month of June, comprising about 6 percent of total June load obligation, or about 28 percent of the load obligation not served by ComEd. Overall, capacity necessary to meet the total June load obligation was obtained from the auction market (6 percent), the bilateral market (16 percent) and self supply (78 percent). Table CAP3 shows the amount of capacity that cleared in the capacity auction by month. This means, for example, that capacity sold for July includes capacity sold for the period from June 2004 to July 2005, capacity sold for

8 Supporting data can be found at Tab 6. The analysis here also relies on data provided at Tabs A, B, C and F of the April 23 Declaration, modified to exclude the Will County, Collins and Bloom units.

9 Supporting data can be found at Tab 7 for the 4,700 MW import case and at Tab 8 for the 700 MW import case.

the period from June to September 2004 and capacity sold for every other period including July.

15. The structural issues identified in the analysis were exhibited in the actual auctions. **[Redacted]** in every auction in which any capacity cleared.[10] (CAP3.) Concentration was high in every auction as the average HHI was **[Redacted]**, the minimum HHI was **[Redacted]** and the maximum HHI was **[Redacted]**. (CAP3.) **[Redacted]** accounted for **[Redacted]** of all capacity sold in the auctions. Not all capacity was offered into the markets, after accounting for bilaterals. Without yet reaching a final conclusion about behaviors in the capacity market in NICA, it is clear that the capacity market is not structurally competitive and that therefore the risk of anticompetitive behavior is high.

16. The actual market results show that the capacity auctions are clearly not competitive, by any standard. While the auctions need to be viewed in the context of the capacity market in NICA, including bilaterals, the results of the auctions are themselves very significant when evaluating the competitiveness of the overall capacity markets in NICA. The auctions serve as the benchmark for the bilateral markets. Thus, if the auctions are not competitive and result in a high price, it is very unlikely that a bilateral seller will sell for less than the auction price. The fact that the auction markets and the bilateral markets do not clear simultaneously and the fact that the auction markets provide parameters for the bilateral markets are fundamental to the market dynamic that makes the auction markets significant.

17. I have evaluated market share and concentration levels for the bilateral market and the auction market together.[11] **[Redacted]** The HHI for the bilateral market was **[Redacted]** while the HHI for the auction markets was **[Redacted]**, for a weighted average capacity market HHI of **[Redacted]**. Overall, the capacity market exhibits high market share and high concentration.

Ex Ante Capacity Market Mitigation

18. Notwithstanding the identified structural market power issues in the NICA capacity market, Mr. Shanker argues against ex ante market power mitigation rules, suggesting instead that "it is appropriate for the MMU to have well defined recourse to protect market participants (both supply and load) from the exercise of market power when warranted by specific events." (Page 10, fn 21) However, the MMU does not now have well defined recourse to protect market participants from the exercise of market power in the capacity market auctions in real time or ex post. That is the reason for

10 A market participant is pivotal when its output is needed in order to clear the market. When the RSI (Residual Supply Index) is less than 1.00 the largest supplier is pivotal. The Auction RSI is the RSI for the largest participant.

11 The results here reflect capacity positions for June as participants are required to provide bilateral positions only for the next month and only on the final day of the preceding month.

the mitigation proposal here. Mr. Shanker does not indicate whether he believes that the MMU now has the referenced well defined recourse or whether he believes that additional authority is required. The MMU's ability to address specific participant actions is defined in the Market Monitoring Plan and is not adequate to address the issues in the NICA capacity market on an ex post basis. The MMU could report on the exercise of market power but has no enforcement authority and no ability to impose remedies. The approach proposed by Mr. Shanker is an ex post approach to market power that is clearly at odds with the Commission's recent statements regarding the appropriateness of clear, ex ante rules governing market behavior. Mr. Shanker provides no specifics. The MMU is proposing a clear, implementable set of ex ante rules governing the exercise of market power precisely to avoid ex post enforcement and the market uncertainty associated with ex post enforcement.

19. As indicated above, there will be 44 additional capacity auctions covering portions of the planning period ending May 31, 2005. The data make it clear that there is a structural issue in the NICA capacity market. The capacity market is not competitive, using the structural screens defined in the Market Power Policy Order. While the identified market structure issues do not guarantee that market participants will actually exercise market power, they are a strong indication that market participants can exercise market power. If the Commission rejects mitigation of this market, it would be rational for participants to exercise market power, recognizing that ongoing scrutiny and reporting may provide some upper bound on prices.

Basis for $30 Offer Cap

20. Mr. Shanker comments that the proposed $30 per MW-day offer cap reveals defects in the PJM capacity market, is not based on identified data, is too difficult to apply, would require the exercise of MMU discretion and is too low. These comments are incorrect.

21. Mr. Shanker does not address the central issue raised by PJM regarding the offer cap. With or without market power, how is the competitive price in the NICA capacity market defined? In the capacity market, with a term of one year, approved by the Commission for NICA, the competitive price is the avoidable cost associated with maintaining a unit as a capacity resource for a year, i.e. the marginal cost of capacity. In a competitive market, this is the price that a rational seller of capacity will offer the market. This is supported by the actual behaviors of sellers in both the PJM MidAtlantic and NICA capacity markets. Actual sellers make substantial amounts of capacity available in both the PJM MidAtlantic and NICA capacity markets at less than $30 per MW-day.[12] The MMU has also had explicit discussions with participants

[12] When comparing prices in NICA and PJM MidAtlantic it is important to remember that the NICA market is an installed capacity market while the PJM MidAtlantic market is an unforced capacity market. The difference is that unforced capacity accounts for the forced outage rates of generating units. It is necessary to multiply PJM MidAtlantic UCAP prices by .94 in order to be comparable to the ICAP prices in NICA.

about supporting higher capacity market offers based on units with going forward costs higher than $30 per MW-day.

22. Mr. Shanker asserts that there are fundamental problems with the PJM capacity market construct. While PJM is working to modify the capacity construct, there are no defects in the current capacity market construct that justify the exercise of market power. The proposed mitigation measure is transitional until a new capacity construct can be put in place.

23. PJM has demonstrated a structural market power issue using the FERC defined market power screens and corroborated this structural issue using actual data from the capacity auctions. Mr. Shanker does not address the structural issue. The fact that there is a structural issue makes it necessary to define a behavioral test for market power to ensure that the structural issue is not manifested as an actual exercise of market power. The actual exercise of market power in the capacity market can only be defined with reference to the competitive price. Mr. Shanker does not attempt to define the competitive price and thus offers no benchmark for defining whether actual market results are competitive.

24. As explained in the April 23 Declaration, the $30 per MW-day proposed offer cap is based on detailed data on the annual avoidable costs associated with maintaining a unit as a capacity resource. The April 23 Declaration relied on cost data from actual recently constructed combustion turbines, and was itemized in detail in the April 23 Declaration. EME argues that this data is insufficient because it is not based on older plants. Current costs to build a new unit can reasonably be used as the basis for a cost-based mitigation measure. In addition, the proposed mitigation includes a clearly specified rule for increasing unit-specific offer caps based on actual going forward costs that would apply to any unit including older units. Nonetheless, to address this criticism and confirm the result, for purposes of this Declaration I have included corroborating cost data for currently operating combustion turbines in PJM and in NICA, ranging in age from 2 to 36 years. This data is taken from individual operating companies in PJM MidAtlantic and NICA. The data indicate a cost for older units of from $22.84 to $28.74 per MW-day, and therefore support that $30 per MW-day is a conservative calculation of the avoidable annual costs associated with maintaining a capacity resource. The data is attached as Table CAP4.[13] [14]

25. Mr. Shanker's affidavit does not provide any basis for rejecting the proposed level of annual avoidable costs. Mr. Shanker comments that the $30 going forward costs do not include property taxes or insurance. That is partially correct. Property taxes are not an avoidable cost because property taxes would continue to be incurred if a unit

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[13] The data in the Owners columns in CAP4 reflects going forward costs provided by the generation owners to the MMU. The data is presented with the level of detail provided to the MMU.

[14] The first column in CAP4 is the only column to include Contractor Overhead and Profit because it is the only case to include the costs associated with an external operating and maintenance contractor. For the Owner cases, operation and maintenance activities were performed by the owner.

were shut down for a year. Therefore, property taxes were excluded from the calculation of going forward costs because they do not meet the definition of annual avoidable cost. Mr. Shanker's going forward cost based on a study by the California Energy Commission (CEC) also excludes property taxes as do most of the studies he cites. In contrast, avoidable insurance costs are properly included in going forward costs and I have included them in my $30 calculation. For example, significant discounts are available for boiler and machinery insurance and general liability insurance if a unit is to shut down for a year. Those discounts reflect avoidable insurance costs that are appropriately includable in the annual avoidable costs.

26. Mr. Shanker suggests that any offer cap should be based on his alternative calculation of $54.80 per MW-day. Mr. Shanker does not base his estimate on actual data from any of EME's units but relies instead on a range of studies with very limited analysis presented concerning the actual components of costs. The CEC study on which he primarily relies does not support a conclusion that $54.80 per MW-day is the current annual avoidable cost of capacity. The CEC study includes "levelized cost estimates for several generic central-station electricity generation technologies." (CEC at page 1) These cost estimates include all fixed and variable costs associated with building the referenced units and do not distinguish between avoidable and unavoidable costs. The costs are also presented on a levelized basis which is equivalent to front-loading the costs when compared to actual current costs. Levelized costs are not a seller's actual current avoidable costs for a year. Mr. Shanker used components of the CEC study costs as the basis for his calculation of avoidable costs. While Mr. Shanker wants to include property taxes and insurance costs from the CEC study, he has not asserted that these are avoidable costs. Further, his number does not include property taxes. Table CAP5 shows the components of Mr. Shanker's calculations. The first column shows the total cost per Mr. Shanker's affidavit.[15] The second column shows the result when levelized, total insurance costs (avoidable plus non-avoidable) are subtracted. The third column shows the result expressed in current dollars (non-levelized).The fourth column shows the result in current dollars when the appropriate level of avoidable insurance costs are added (current dollars). The result from the appropriate application of Mr. Shanker's approach to the CEC study is $30.16 per MW-day. (See Table CAP5.)

27. In addition, the $30 per MW-day going forward cost is conservative in that it is based on the costs of a combustion turbine and the assumption that there are zero net revenues derived from the energy market to offset these costs. In actual operations, combustion turbines do receive net revenues from the energy market. For example, the PJM Interconnection State of the Market Report for 2003 showed that the theoretical net revenue for a new CT in PJM was $15,380 per MW-year in 2003 and was $36,169 per MW-year on average from 1999 through 2003. This is equivalent to

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15 Representatives of the MMU have spoken with CEC staff, obtained the underlying CEC spreadsheet and attempted to validate Mr. Shanker's calculations. The correct total levelized cost per Mr. Shanker's position is $54.12 rather than the $54.80 he reports. This is a result of rounding in the hard copy CEC tables relied on by Mr. Shanker.

$42 per MW-day and $99 per MW-day, respectively.[16] MMU analysis of actual net revenues for operating CTs in PJM in 2003 indicates that actual net revenues are consistent with the theoretical data.

28. The $30 per MW-day going forward cost is also a conservative calculation of the annual cost of capacity because it does not account for the significant costs of taking a unit out of service for a year. If the alternatives considered are operating the unit for a year and shutting the unit down for a year, the incremental costs associated with shutting the unit down for a year should be considered. The costs associated with shutting a unit down for a year (mothballing) are not considered in this analysis. The result is to make clear that the $30 per MW-day annual going forward cost is a conservative calculation.

29. NRG contends that the $30 offer cap is too low and speculates that it would drive NICA units into economic retirement as early as this summer. NRG cites a NERC document for the claim that MAIN's projected July 2004 reserve margin is significantly below MAIN's recommended 14.12 % reserve margin.[17] The referenced MAIN summer assessment predated the integration of NICA into PJM and does not support the NRG claim. In fact, the referenced MAIN summer assessment states that the summer reserve margin could be as low as 8.7 percent or as high as 29.7 percent.[18] The principal concern cited in the MAIN assessment was that some load did not have firm capacity contracts and that available capacity was therefore not committed to serving load in MAIN. Integration into PJM has addressed this issue because load-serving entities must purchase capacity resources equal to 115% of their summer peak loads, under the requirements approved by the Commission for NICA. That requirement is being satisfied in NICA on an ongoing basis; all load serving entities covered 100 percent of their load obligations with firm capacity as of June 1. Moreover, NRG's speculation that the short-term (11 month) imposition of necessary market-power mitigation in NICA will force economic retirements in MAIN is not credible and no evidence is provided to support the claim.

30. While NRG does not contest the need for mitigation, it asserts the need to modify PJM's overall capacity market rules. PJM is currently considering alternatives to the current PJM capacity rules. The present mitigation proposal has a far narrower objective, i.e., to address market power concerns in the separate NICA capacity

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16 PJM Interconnection State of the Market Report 2003, pages 57 et seq.

17 The referenced document is: 2004 Summer Assessment, Reliability of the Bulk Electricity Supply in North America, North American Reliability Council, May 2004. The MAIN section is attached as Tab 9.

18 The MAIN assessment states: "If only capacity that is planned and committed to serving firm load within MAIN is considered, the reserve margin would be 8.7%, which is below MAIN's recommended 14.12% reserve margin. However, MAIN also has 11,412 MW of operable uncommitted generation potentially available to serve load this summer. It is uncertain how much of this uncommitted generation will be available to serve MAIN load this summer. The reserve margin considering all operable generation in MAIN (committed within MAIN plus uncommitted) is forecasted to be 29.7% which is above MAIN's 14.12% reserve margin recommendation for the upcoming summer."

market that has relatively few sellers and relatively high concentration, for the limited time period that such market is in place. Where there is a current need for mitigation, the remedy should not await development of complex new capacity pricing approaches.

Basis for Adders to $30 Offer Cap

31. PJM's NICA initial capacity market mitigation proposal allowed participants in the capacity market the opportunity to demonstrate that their cost of capacity for specific units is greater than $30 per MW-day. In PJM's request for rehearing and the April 23 Declaration, we refined this proposal to address concerns about Market Monitor discretion in this area. Specifically, Tab K to the April 23 Declaration included a complete list of the categories of costs that PJM proposed should qualify for the demonstration of costs in excess of $30 per MW-day. PJM offered, if the Commission so determines, to include this definition of qualifying cost categories in the filed PJM market rules, making them subject to Commission approval.

32. This process need be neither complex, lengthy or biased in any way. For example, if a generation owner demonstrated the type of insurance costs used in California, the costs would simply be added to the going forward costs and the level of offer cap for the unit would be increased correspondingly. As part of monitoring the existing ICAP market, the MMU has gone through this calculation and validation of actual going forward costs with individual PJM generation owners for multiple, specific units. The process was completed in less than two weeks.

33. Duke comments that this process still reserves too much discretion to the Market Monitor. However, the factors it cites are factors that PJM is asking the Commission to establish through this filing. Once the Commission accepts that mitigation is needed, that actual annual avoidable costs are properly compensated for sellers subject to mitigation, and that PJM adopted the appropriate definition and itemization of such costs in its request for rehearing, then the sole role of the Market Monitor is to verify that the seller has documented such costs, as approved by the Commission. The Commission can also establish procedures for recourse to the Commission in the event of disagreements, or can reserve to itself the determination of whether a generator is entitled to compensation above the $30 cap.

I declare under penalty of perjury that the foregoing is true and correct.

Executed this 18th day of June 2004.

Joseph E Bowring

Joseph E. Bowring

Table CAP 1

2004 Monthly Capacity Credit Market Schedule - Last Updated 6/4/2004

MARKET TERM	MARKET RUN DATE											
	January	February	March	April	May	June	July	August	September	October	November	December
February 1, 2004-May 31, 2004	1/13/04											
March 1, 2004-May 31, 2004		2/10/04										
April 1, 2004-May 31, 2004			3/9/04									
June 1, 2004-May 31, 2005	1/23/04		3/11/04	4/13/04*	5/4/04* 5/21/04*							
June 1, 2004-December 31, 2004				4/15/04*	5/24/04*							
June 1, 2004-September 30, 2004			3/16/04	4/20/04*	5/25/04*							
June 1, 2004-July 31,2004		2/12/04	3/18/04		5/26/04*							
July 1, 2004-September 30, 2004						6/21/04*						
August 1, 2004-September 30, 2004						6/23/04*	7/22/04*					
October 1, 2004-December 31, 2004					5/27/04*		7/28/04*	8/17/04*	mm/dd/yy*			
November 1, 2004-December 31, 2004										mm/dd/yy*		
January 1, 2005-December 31, 2005				4/30/04						mm/dd/yy	mm/dd/yy	mm/dd/yy
January 1, 2005-May 31, 2005					5/28/04*					mm/dd/yy*	mm/dd/yy*	mm/dd/yy*
February 2004	1/15/04											
March 2004	1/20/04	2/19/04										
April 2004	1/22/04	2/24/04	3/23/04									
May 2004		2/26/04	3/25/04	4/22/04								
June 2004			3/30/04	4/27/04*	5/27/04*							
July 2004				4/29/04*		6/8/04* 6/24/04*						
August 2004						6/10/04* 6/28/04*	7/26/04*					
September 2004						6/29/04*	7/27/04*	8/19/04*				
October 2004							7/29/04*	8/24/04*	mm/dd/yy*			
November 2004								8/26/04*	mm/dd/yy*	mm/dd/yy*		
December 2004									mm/dd/yy*	mm/dd/yy*	mm/dd/yy*	
January 2005										mm/dd/yy*	mm/dd/yy*	mm/dd/yy*
February 2005											mm/dd/yy*	mm/dd/yy*
March 2005												mm/dd/yy*

Notes:

Run Dates with an * indicate that both a PJM Unforced Capacity Credit Market and a NICA Installed Capacity Market are to be conducted.
Run Dates without an * indicate that only a PJM Unforced Capacity Credit Market will be conducted.

Monthly and Multi-Monthly Markets are opened 7am EPT and closed 10am EPT on the market run date.

Tab 2 – Contains privileged information that was redacted.

Tab 3 – Contains privileged information that was redacted.

Tab 4 – Contains privileged information that was redacted.

Table CAP 5

CEC Report Summary ($/MW-Day)

Plant	CEC Report	CEC Report Insurance Omitted	CEC Report Insurance Omitted	CEC Report PJM Insurance Added
On Site Payroll & Burden	Levelized	Levelized	Current	Current
All On Site Employee or Contractor Salary and Benefits	$31.82	$31.82	$26.89	$26.89
Administration and Operations Expenses				
Employee Expenses				
Environmental				
Safety				
Buildings & Grounds				
Other Supplies & Expenses				
Communications				
Insurance	$22.30	$0.00	$0.00	$3.27
Control Room/Laboratory				
Total	$22.30	$0.00	$0.00	$3.27
Maintenance Expenses (No Major Maintenance)				
Painting				
Electrical & Controls				
Cooling System				
Substation/Interconnects				
Gas Turbine & Generator (excluding major maintenance)				
Water Supply Pipeline and Booster Station				
Fuel Facility				
Plant Test, Inspection and Analysis				
Miscellaneous Maintenance				
Chemicals and Lubricants				
Total	$0.00	$0.00	$0.00	$0.00
Contractor Overhead and Profit				
Contract Operator Annual Fee				
Operator Overhead Charge (G&A)				
Total	$0.00	$0.00	$0.00	$0.00
To Go Cost Grand Total	$54.12	$31.82	$26.89	$30.16

Tab 6 – Contains privileged information that was redacted.

Tab 7 – Contains privileged information that was redacted.

Tab 8 – Contains privileged information that was redacted.

2004
SUMMER
ASSESSMENT

Reliability of the
Bulk Electricity Supply
in North America

North American Electric Reliability Council

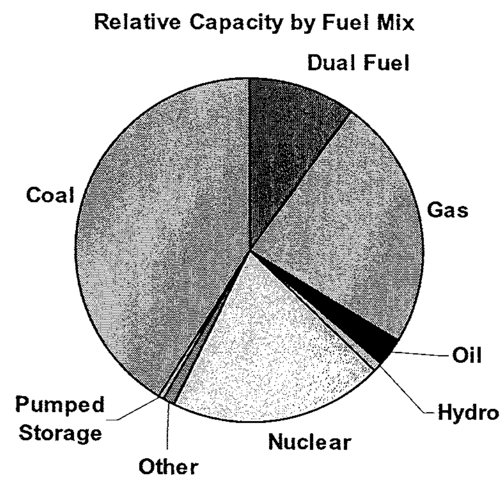
May 2004

Table of Contents

MAIN

Projected Internal Demand	57,662	MW
Interruptible Demand & DSM	3,191	MW
Projected Net Internal Demand	54,471	MW
Last Summer's Peak Demand	57,229	MW
Change	0.8	%
All-Time Summer Peak Demand	57,229	MW
Net Operable Capacity	58,910	MW
Projected Purchases	1,589	MW
Projected Sales	1,275	MW
Adj. to Purchases & Sales	—	MW
Net Capacity Resources	59,224	MW
Capacity Margin	8.0	%
Reserve Margin [1]	8.7	%
With Uncommitted Resources		
Uncommitted Resources	11,412	MW
Total Net Capacity Resources	70,636	MW
Capacity Margin	22.9	%
Reserve Margin [1]	29.7	%

[1] MAIN uses Reserve Margin, not Capacity Margin, as its standard to assess adequacy.



Demand

Mid-America Interconnected Network, Inc. (MAIN) total internal non-coincident peak demand forecast for summer 2004 is 57,662 MW, including 3,191 MW of interruptible and DSM load, assuming normal weather conditions. The projected summer peak load is 433 MW (0.76%) higher than last summer's peak demand. For the 2004 summer, the region is expected to be a net firm importer of 314 MW.

Resources

If only capacity that is planned and committed to serving firm load within MAIN is considered, the reserve margin would be 8.7%, which is below MAIN's recommended 14.12% reserve margin. However, MAIN also has 11,412 MW of operable uncommitted generation potentially available to serve load this summer. It is uncertain how much of this uncommitted generation will be available to serve MAIN load this summer. The reserve margin considering all operable generation in MAIN (committed within MAIN plus uncommitted) is forecasted to be 29.7%, which is above MAIN's 14.12% reserve margin recommendation for the upcoming summer.

The projected internal demand includes 4,166 MW of load within MAIN not supplied with firm capacity contracts but rather by liquidated damages (LD) contracts, which to MAIN's knowledge are not supported by firm capacity contracts. Although a requirement is not in place that uncommitted generation within MAIN be available during the summer to serve this load, the load being served by LD contracts is less than 40% of these uncommitted resources.

Based on committed and potentially available uncommitted resources, MAIN expects, but cannot ensure, that there will be capacity available to serve all firm load in MAIN. MAIN will continue to monitor the load and capacity situation as the summer season approaches.

The 70,636 MW of net capacity resources includes about 1,500 MW of generation expected to come on-line in 2004 before or during the summer period. This 1,500 MW figure is net of 130 MW that was retired, mothballed, or temporarily removed from service in 2003. Capacity maintenance is not scheduled for July or August, and only 874 MW and 743 MW of capacity maintenance is scheduled for June and September, respectively.

Neither fuel problems nor limitations of hydro resources are expected. Hydro resources account for less than 2% of MAIN's installed capacity.

Transmission

In general, the transmission system is expected to perform reliably under a wide range of operating conditions. On the whole, import capabilities into MAIN from surrounding regions are considered adequate.

The table below compares MAIN's Import First Contingency Total Transfer Capabilities (FCTTCs) for the summers of 2003 and 2004. The FCTTC values in the table below were developed to help assess MAIN's resource supply reliability (these values are not the same as the Available Transfer Capabilities (ATCs) posted on an OASIS node). The notes associated with Figure 3 of this Summer Assessment are also applicable to the table below.

Table 4: MAIN Import First Contingency Total Transfer Capabilities (FCTTC) (MW)

	2004	2003
ECAR	2,600	2,500
TVA	1,900	2,400
SERC West	2,200	900
SPP*	2.600	2,100
MAPP*	1,200	1,200

* Operating guides used as required

Based on results of the 2003 MAIN Summer Assessment, Alliant West, American Transmission Company, and Dairyland Power Cooperative agreed to the installation of a temporary transformer near Galena, Illinois. This 44 MVA 161/69 kV portable transformer is planned to remain in service for the duration of the upcoming summer to address south-to-north transfers within MAIN and was included in the base model used for the 2004 Summer Assessment.

Based on MAIN's 2004 summer transmission study, these transfer capabilities are expected to be limited by contingency loading on a single facility, the Salem 345/161 kV transformer:

- Import capability into Wisconsin and Upper Michigan (WUMS) from northern Illinois
- Import capability into Alliant West from several directions
- Import capability into northern Illinois from Wisconsin and Upper Michigan
- Import capability into northern Illinois from Iowa is limited by the contingency loading of the Emery-Lime Creek 161 kV line in ALTW. The loading of the Emery-Lime Creek 161 kV line is influenced by generation additions in the area.

These limitations are being managed by their respective transmission system operators, and are not expected to pose a reliability concern for the upcoming summer.

A complete listing of all transmission improvements since summer 2003 and transfer capabilities are available in the *2004 MAIN Summer Transmission Assessment Study* report. (See MAIN website at http://www.maininc.org/)

In response to NERC's February 10, 2004, blackout recommendations, MAIN is making simultaneous transfer capabilities assessments and the impact of the loss of reactive power supply on transfer capabilities.

Operations

Local environmental restrictions on certain generation units are not expected to significantly impact availability during peak load conditions.

The following facilities will also require continued monitoring and management by the appropriate reliability coordinators and transmission system operators:

- Historically constrained MAPP to MAIN interface, which will be managed as necessary using special protection schemes (SPS) to maintain reliable operation for the upcoming summer.
- Bland-Franks 345 kV line in southern MAIN, which experienced heavy power flows during 2003 and required implementation of TLR.

These limitations are being managed by their respective transmission system operators, and are not expected to pose a reliability concern for the upcoming summer.

The NERC standing committees recently approved the short-term recommendations of Alliant West TLR Task Force. The recommendations[1] are intended to address the higher levels of TLRs in the Alliant West area in central and eastern Iowa expected for this summer. The results of implementing the short-term recommendations during the four-month pilot project will be evaluated to determine whether the practices and procedures would be applicable across the entire interconnection.

[1] See NERC website at http://www.nerc.com/~filez/awttf.html

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 Washington, D.C., this 18th day of June, 2004.

Barry S. Spector

WRIGHT & TALISMAN, P.C.
1200 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 393-1200

Of Counsel for

PJM Interconnection, LLC