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October 1, 2004

Honorable Magalie Roman Salas
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E., Room 1A
Washington, D.C. 20426

Re: PJM Interconnection, L.L.C., Docket No. ER04-___-000
(Market-Based Regulation Offers in the PJM West/South Region)

Dear Ms. Salas:

Pursuant to section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d, PJM Interconnection, L.L.C. ("PJM") files for a change in rates to permit market-based offers in the expanded PJM market for regulation service in the portion of the PJM region covered by the geographic territories of Allegheny Power,[1] American Electric Power Company ("AEP"),[2] Commonwealth Edison Company (including Commonwealth Edison Company of Indiana) ("ComEd"), The Dayton Power and Light Company ("Dayton"),

1 The Allegheny Power operating companies are Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company (collectively, "Allegheny Power").

2 The AEP-east operating companies joining PJM are Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, and Wheeling Power Company.

Duquesne Light Company ("Duquesne"), and Virginia Electric Power Company ("Virginia Power").

As discussed below, after the integration of Virginia Power into PJM, the regulation market area for these companies (the "PJM West/South Regulation Zone") is sufficiently large such that the expected supply of regulation far exceeds the regulation requirement for the area. Indeed, supply is expected to exceed by over 2500 megawatts the required on-peak regulation need of 784 megawatts. As a result, as shown below, no single supplier of regulation service is pivotal. While market shares [redacted] Herfindahl-Hirschman Indices ("HHIs") are well below 2500. Additionally, other factors exist to mitigate the ability of these companies to exercise market power.

PJM is proposing that market-based offers of regulation service be permitted upon the integration of Virginia Power into PJM, but no earlier than 60 days after the date of this filing (December 1, 2004).

I. Background

Since 2000, PJM has been operating a market-based regulation market within the Mid-Atlantic Area Coordination Council ("MAAC") region.[3] This market has operated successfully, increasing the supply of regulation and enabling PJM to better match real-

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[3] See PJM Interconnection, L.L.C., 91 FERC ¶ 61,021 (2000).

time supply with changes in real-time demand in accordance with North American Electric Reliability Council ("NERC") reliability requirements.[4]

With the integration of several new transmission systems and accompanying generation, including Allegheny Power, AEP, Dayton, and Duquense in the East Central Area Reliability ("ECAR") region,[5] ComEd in the Mid-American Interconnected Network ("MAIN") reliability region, and the anticipated expansion of operations into the Virginia and Carolina Reliability Region ("VACAR") with the scheduled integration of Virginia Power, PJM is now able to extend market-based regulation service throughout its footprint.

PJM initially planned to provide ancillary service requirements separately in each of the reliability regions in which the PJM markets would operate. Thus, PJM operated separate ancillary service markets in the Allegheny service area after its integration, and it currently operates separate ancillary service markets in the ComEd service area. PJM

4 See, e.g., 2003 State of the Market Report for PJM Interconnection, L.L.C. (Mar. 4, 2004), at 27, available at http://www.pjm.com/markets/market-monitor/som.html. ("The MMU has reviewed structure and performance indicators for the Regulation Market and concludes that the Regulation Market functioned effectively and produced competitive results in 2003.").

5 On October 1, 2004, additional ECAR transmission owners, the AEP system-east region companies and Dayton, will be integrated into PJM. On January 1, 2005, another ECAR transmission owner, Duquesne, is scheduled to be integrated into PJM.

expected it would operate separate markets for regulation and spinning reserves in MAIN, ECAR, VACAR and MAAC, following further integrations.[6] The PJM Tariff[7] and Operating Agreement[8] therefore established "Control Zones" to accommodate these separate markets. Each of the reliability regions in which PJM operates would have one or more "Control Zones" in which PJM would operate ancillary service markets, the boundaries of which would be designated in the PJM manuals.[9]

However, with the integration into PJM of several additional transmission owners in the ECAR, MAIN, and VACAR reliability regions, it became apparent that multiple "Control Zones" would not provide PJM the flexibility to establish markets and provide services in the most efficient manner across the larger geographic footprint that PJM now encompasses. PJM market participants sought the establishment of broader areas for the provision of PJM's various ancillary services and operations, larger than the transmission owner zones in a single reliability region. PJM therefore initiated discussions with the staffs of the various reliability councils. It ultimately received their agreement that

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6 See Declaration of Joseph E. Bowring attached hereto as Exhibit A, ¶ 3 ("Bowring Declaration").

7 PJM Open Access Transmission Tariff designated as PJM Interconnection, L.L.C. FERC Electric Tariff Sixth Revised Volume No. 1 ("PJM Tariff").

8 Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., designated as PJM Interconnection, L.L.C. Third Revised Rate Schedule FERC No. 24 ("Operating Agreement").

9 See Operating Agreement §§ 1.7D and 1.20C. See also proposed section 1.47B of the Operating Agreement and proposed section 1.49C of the PJM Tariff jointly filed by PJM and Virginia Power on May 11, 2004 in Docket No. ER04-829 ("PJM South Filing").

combining the ECAR, MAIN, and VACAR zones for the purpose of providing regulation service was acceptable.[10]

To implement the new arrangements, on September 1, 2004, PJM filed revisions to the PJM Tariff and the Operating Agreement, unanimously supported by the PJM members, to create larger "Regulation Zones."[11] Regulation Zones will be "any of those one or more geographic areas, each consisting of a combination of one or more Control Zone(s) as designated by [PJM] in the PJM Manuals, relevant to the provision of, and requirements for, regulation service.[12] In its Regulation Zone Filing, PJM noted that, assuming that the Commission accepted the PJM Tariff and Operating Agreement changes establishing "Regulation Zones," PJM would designate the combination of ComEd, the AEP transmission system, Dayton, and Allegheny Power Control Zones as one Regulation Zone (the "PJM West/South Regulation Zone").[13] Once Duquesne and Virginia Power join PJM, they will be added to this Regulation Zone. The MAAC region

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10 See Bowring Declaration ¶ 4. For now, PJM still plans separate spinning reserve markets for each reliability council. Id.

11 See PJM Transmittal Letter, Docket No. ER04-1175 (Sept. 1, 2004) ("Regulation Zone Filing"). The Commission accepted for filing the PJM Tariff and Operating Agreement revisions by letter order dated September 28, 2004 to be effective October 1, 2004.

12 See section 1.38A of the Appendix to Attachment K of the PJM Tariff and Schedule 1 of the Operating Agreement filed with, and accepted by, the Commission in Docket No. ER04-1175.

13 Regulation Zone Filing at 7.

will continue to remain a separate Regulation Zone.[14] The creation of these larger zones likely will increase the efficiency of the regulation market and PJM's operations.

In addition, as PJM stated in its Regulation Zone Filing, "the larger regulation market enabled by these changes may facilitate a subsequent request to the Commission for market-based rate authority" for regulation, similar to the prevailing market-based regime for regulation in the MAAC region.[15] Consistent with this expectation, PJM hereby files this request for authorization for market-based rates in the PJM West/South Regulation Zone.

II. Standard for Market-Based Ancillary Service Markets

A. Legal Framework

In Ocean Vista Power Generation, L.L.C., 82 FERC ¶ 61,114 (1998) ("Ocean Vista"), the Commission provided guidance for determining whether market-based rates should be authorized for ancillary services. First, the applicant must define the relevant product market.[16] The Commission has concluded that each ancillary service constitutes a separate product market.[17] Second, the applicant must provide a description of the relevant geographic market.[18] Third, the applicant must evaluate the market shares for all

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14 Id.

15 Id. at 8.

16 Ocean Vista at 61,407.

17 Id.

18 Id.

suppliers of the relevant ancillary service (here regulation) in the geographic market.[19] Fourth, applicants must analyze the impact on market power of the ability of competitors to enter the specific ancillary services market.[20]

More recently, in AEP I,[21] the Commission established two "indicative screens" for the evaluation of market power -- a pivotal supplier analysis and a wholesale market share analysis. The pivotal supplier analysis evaluates whether a market participant unilaterally may exercise market power because its resources must be used to meet market demand. The wholesale market share analysis examines concentration in the market, focussing on suppliers that have market shares greater than 20 percent. In the event that a market-based rate applicant fails these screens, the applicant can use a more refined test (labeled by the Commission as a delivered price test). Under this test, market concentrations are calculated using the HHI,[22] and, in AEP I, the Commission indicated that a showing of an HHI less than 2500 in the relevant market under this test would constitute a showing of a lack of market power.[23]

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19 Id.

20 Id.

21 AEP Power Mktg., Inc., 107 FERC ¶ 61,018 ("AEP I"), order on reh'g, 108 FERC ¶ 61,026 (2004) ("AEP II").

22 Id. at P 110.

23 Id. at P 111. See also AEP II at P 105 (denying rehearing request to lower the HHI threshold) ("the 2500 HHI threshold, taken in context with the other tests, provides a reasonable balance between the need to identify applicants possessing market power and the goal of avoiding undue regulatory burdens imposed by false positives"). The Commission routinely has used the 2500 threshold in evaluating whether a pipeline possesses significant market power. See Shell Pipeline Co.
(Cont'd . . .)

Nonetheless, historically, the Commission has not considered any market share thresholds to act as bright line tests of market power. "While the Commission generally concludes that market power is not a concern when the results are below the thresholds, it does not necessarily follow that market power is a concern when the thresholds are exceeded, depending on other relevant factors."[24] Several relevant mitigating factors can ameliorate market power concerns indicated by market share analysis. One significant factor that mitigates the ability to exercise market power is whether available supply far exceeds demand. In such situations, individual suppliers, even those with market shares above 20 percent, likely would not be able to exercise market power. HHI thresholds similarly are not determinative of market power when there is a substantial excess of supply over demand in a market.

(. . . cont'd)

L.P., 103 FERC ¶ 61,236, at n.11 (2003); see also Wolverine Pipe Line Co., 92 FERC ¶ 61,277, at n.15 (2000); TE Prod. Pipeline Co., L.P., 92 FERC ¶ 61,121, at n.43 (2000); Longhorn Partners Pipeline, L.P., 83 FERC ¶ 61,345, at n.8, affirmed, 85 FERC ¶ 61,206 (1998) ("In previous cases, the Commission used an HHI of 2500 as an initial screen, and then reviewed the pipeline's market share and other factors in order to determine whether the pipeline possessed significant market power.").

24 Atl. City Elec. Co., 86 FERC ¶ 61,248, at 61,903 (1999) ("Atlantic"); see also New England Power Pool, 95 FERC ¶ 61,074, at 61,209, n.29 (2001) ("[T]he Commission has repeatedly stated that it does not consider a 20 percent market share figure to be an absolute bright line, and other factors must be considered."); Cent. Hudson Gas & Elec. Corp., 86 FERC ¶ 61,062, at 61,235 ("Central Hudson I"), order on reh'g, 88 FERC ¶ 61,138 (1999) ("Central Hudson II"). ("[T]he Commission has not established a 20 percent market share as an absolute, bright-line test."); New England Power Pool, 85 FERC ¶ 61,379, at 62,472 (1998), reh'g denied, 95 FERC ¶ 61,074 (2001) ("[T]he Commission has not established a 20 percent market share as an absolute, bright line test of market power.").

As the Commission explained in Central Hudson I when addressing ancillary service markets in the New York ISO:

> [T]he fact that a number of different suppliers are capable of fully satisfying the ISO's needs is an important factor. In all cases, the total potential supply of a particular type of reserve is at least twice the estimated requirement, and sometimes much greater. Differences between supply and demand of this magnitude are likely to deter the exercise of market power, because no individual supplier is irreplaceable. Each supplier -- even one with a 51 percent share of the supply -- can be completely displaced with capacity from other suppliers in light of the substantial differences between total supply and total demand.[25]

Similarly, in Buckeye Pipe Line Co., L.P., Opinion No. 360, 53 FERC ¶ 61,473, at 62,670 (1990) ("Buckeye"), order on reh'g, Opinion No. 360-A, 55 FERC ¶ 61,084 (1991), the Commission found that, although the applicant had a market share of 38.5 percent in a market, it did not have market power because there was "substantial excess capacity in the market."[26]

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25 Central Hudson I at 61,237 (emphasis added).

26 In Buckeye, the Commission also found that Buckeye did not have market power in another market where the HHI was around 3050 and Buckeye's market share was 28.5 percent, noting that the "record establishes that there is significant excess capacity in this market." Id. at 62,671. See also Central Hudson II at 61,402 ("We also noted other factors that would mitigate market power, such as the existence of generating capacity substantially in excess of ancillary service requirements."); Kaneb Pipe Line Operating P'ship., L.P., 83 FERC ¶ 61,183, at 61,761 (1998) ("[A]n HHI near 2500, but with excess capacity of over three times the consumption . . . plus the fact that Kaneb's delivery market share is less than Williams' market share, indicates that Kaneb does not have significant market power."); N.Y. State Elec. & Gas Corp., 81 FERC ¶ 61,020, at 61,137 (1997) ("[W]hen there is a high HHI, the Commission looks at other factors such as ease of entry and excess capacity which may prevent an applicant from exercising market power."); Ameren Servs. Co., 101 FERC ¶ 61,202, at P 45 (2002) ("[M]arket power concerns are less severe when excess capacity is available.").

In addition, other factors, such as the potential for entry into the market, market monitoring plans, and mitigation plans (including offer capping), also may indicate that a seller with a market share over 20 percent likely will not be able to exercise market power.[27]

B. Market Analysis for PJM West/South Regulation Market

Relevant Product Market: Consistent with Ocean Vista, the relevant product market is the regulation market. The provision of regulation constitutes a separate ancillary service market as there are no good substitutes for the regulation product in the PJM market.[28]

Relevant Geographic Market: Because PJM is seeking market-based pricing for the regulation market only upon Virginia Power joining PJM, and PJM will operate a single regulation market across Allegheny Power, ComEd, AEP, Dayton, and Virginia Power, the relevant geographic market is the PJM West/South Regulation Zone, including Virginia Power.[29] Imports of regulation are not possible because the service must be provided dynamically, not through a fixed schedule.[30] The PJM West/South Regulation Zone must be supplied regulation by generators located in that zone.[31]

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27 See New England Power Pool, 95 FERC at 61,209.

28 Bowring Declaration ¶ 11.

29 Duquesne also is included in the PJM market monitor's analysis. However, Duquesne's integration into PJM has a de minimis impact on the overall market analysis results. Bowring Declaration ¶ 15.

30 See id. ¶ 13.

31 Id.

Suppliers in this geographic market include all entities that own generating capacity in the PJM West/South Regulation Zone that can be used to provide regulation.[32]

Pivotal Supplier Analysis: Most importantly, PJM's market monitor evaluated the PJM West/South Regulation Zone regulation market and concluded that no single supplier of regulation is expected to be pivotal.[33] The expected supply of regulation far exceeds the regulation needs of the market, such that the removal of any one supplier would not prevent the market from being served completely through the offers of other suppliers. The market monitor notes that "[t]he total supply of regulation in the [PJM West/South Regulation Zone] is 3,292, the maximum demand for regulation is 784 MW <u>and thus there is excess supply of 2,508 MW or 3.2 times the peak regulation demand.</u>"[34] Moreover, "no single supplier is pivotal and [redacted] could withhold their regulation capability and there would be adequate capability to meet the regulation requirement."[35] Consistent with <u>Central Hudson I</u>, any supplier's resources

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32 <u>Id.</u>

33 <u>Id.</u> ¶ 29.

34 <u>Id.</u> ¶ 35 (emphasis added).

35 <u>Id.</u> ¶ 36. Even with a more refined delivered price test, the market monitor concluded that the output of [redacted] is not required to meet demand associated with the first three price quartiles, and the output of [redacted] is not needed considering all four price quartiles. <u>Id.</u> ¶ 44.

can be completely displaced with capacity from other suppliers because the supply of the product is more than three times the demand.

Market Share Analyses: The PJM market monitor determined market shares in the regulation market as the ratio of a participant's uncommitted regulation capacity to the total uncommitted regulation capability for the area.[36] Uncommitted regulation capacity "is calculated by subtracting the regulation requirement associated with the native load obligation on the minimum peak demand day, in a given season, from the regulation capability otherwise controlled by the participant and competing suppliers."[37] Total uncommitted regulation capability for a relevant geographic region is "the sum of the individual participant net regulation capabilities."[38]

Consistent with AEP I, the market monitor evaluated market shares against a 20 percent market share screen.[39] He also calculated HHIs "to provide context for the market share results."[40] The market share results for the PJM West/South Regulation Zone show [redacted]. The HHIs, however, are well below 2500, ranging from 2097 in the summer to 2130 in the winter.[41]

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36 Id. ¶ 23.

37 Id.

38 Id.

39 Id. ¶ 31.

40 Id. ¶ 17.

41 Id. ¶ 30.

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36 Id. ¶ 23.

37 Id.

38 Id.

39 Id. ¶ 31.

40 Id. ¶ 17.

41 Id. ¶ 30.

Mitigating Factors: As noted, the market monitor identified a critical threshold consideration that would make strict reliance on market shares improper. Consistent with Commission precedent, as well as his own prior evaluation of regulation markets in the MAAC region, the market monitor examined the ratio of total regulation supply to maximum regulation demand.[42] As noted, he determined that there is an excess supply of 2508 MW, or 3.2 times the peak regulation requirement.[43]

Consistent with Central Hudson I, Buckeye, and other cases,[44] the excess supply of regulation in the PJM West/South Regulation Zone mitigates significantly the potential exercise of market power. As the Commission explained in Central Hudson I, "[d]ifferences between supply and demand of this magnitude are likely to deter the exercise of market power, because no individual supplier is irreplaceable."[45] The supply in the PJM West/South Regulation Zone is more than 3.2 times the demand.[46] Given the excess supply that ameliorates potential market power concerns and that no supplier is expected to be pivotal once Virginia Power joins PJM, conditions in the PJM West/South Regulation Zone support market-based rates as proposed by PJM.

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42 Id. ¶ 33.

43 Id. ¶ 35.

44 See cases cited in footnote 26 supra.

45 Central Hudson I at 61,237.

46 See Kaneb Pipe Line at 61,761 ("an HHI near 2500, but with excess capacity of over three times the consumption . . . indicates that Kaneb does not have significant market power.").

Notably, the market analysis that supported the Commission's authorizing market-based rates in the MAAC regulation market similarly revealed that there was an excess supply of regulation in that market such that "the individual suppliers that have market shares above the 20% threshold likely would not be able to exercise market power."[47] The Commission should apply that same reasoning here.

Other mitigating factors also warrant affording market shares diminished importance here. Because a regional transmission organization ("RTO") oversees the supply of regulation, entry into the market is relatively easy, as evidenced by the substantial generation additions in PJM in recent years.[48] Additionally, with relatively modest investment (such as the addition of automatic generation control) some units that currently do not provide regulation can provide regulation in response to the price signals generated by a market-based regulation market. Market participants do not have the ability to block entry by others. With appropriate market signals, supply could increase

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47 PJM Interconnection, L.L.C., Docket No. ER00-1630, Transmittal Letter (Feb. 15, 2000), at 16.

48 See Revised Filing Requirements Under Part 33 of the Commission's Regulations, Order No. 642, 1996-2000 FERC Stats. & Regs., Regs. Preambles ¶ 31,111, at 31,900 (2000), order on reh'g, Order No. 642-A, 94 FERC ¶ 61,289 (2001). ("RTOs can mitigate market power, eliminate rate pancaking and better manage grid congestion, thereby enlarging geographic markets."); see also Atlantic at 61,905 ("We think the PJM-OI provides significant assurance to prospective generation market entrants that they will be treated in a non-discriminatory manner, thereby helping to ensure that there is sufficient entry into generation markets to defeat price increases that may result from sustained exercises of market power."); see also Atl. City Elec. Co., 86 FERC at 61,903 (Mitigating factor included "the existence of an independent regional transmission organization controlling transmission system, and using nondiscriminatory market rules that encourage entry.").

even more. Only after operation of the market with market-based rates for a period of time can the full supply response be realized and evaluated.

There also will be a $100 offer cap on all market-based regulation offers,[49] as in the MAAC region today. This mitigation cap limits regulation prices if supply is short for any reason at any given time and is a further mitigating factor. Any potential price excursions could not exceed this offer cap. In addition, the presence of PJM's market monitor and the PJM market monitoring plan serve to inhibit potential exercises of market power.[50]

Conclusion: Based on the foregoing, PJM requests market-based rate authority for the regulation market in the PJM West/South Regulation Zone, upon Virginia Power's integration into PJM. Consistent with the Commission's regulations, however, PJM proposes an effective date no earlier than 60 days after the date of this filing, which is December 1, 2004. A market-based regulation market will facilitate a

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49 PJM Tariff Appendix to Attachment K § 1.10.1A(e), Operating Agreement Schedule 1 § 1.10.1A(e).

50 See, e.g., Va. Elec. Power Co., 108 FERC ¶ 61,242, at P 32 (2004) ('[W]e find that, when [Virginia Power] is integrated into Expanded PJM, it satisfies our generation market power concerns, as indicated by its passage of the screens, and that PJM's Commission-approved market monitoring and mitigation provides an adequate check on the potential to exercise market power within PJM."); Central Hudson I at 61,238-39 (factor in approving market-based rates for operating reserves and regulation was that the independent system operator would be monitoring the markets for market power and have the obligation to report exercise of market power to the Commission and to recommend mitigating steps.) New England Power Pool, 95 FERC at 61,209 ("other factors such as . . . the monitoring and mitigation plans, also suggested that it was not likely to exercise market power and that the ISO would be able to address any market problems that develop.")

more efficient and robust regulation market in the PJM West/South Regulation Zone, while providing appropriate incentives for participants to provide regulation. As discussed above, based on current expectations, market power should not be a concern in this market.

The PJM market monitor, of course, will evaluate on an ongoing basis the actual operation of the regulation market, once AEP and Dayton are integrated on October 1, 2004, and following Virginia Power's integration. In the event that actual market operations in the PJM West/South Regulation Zone do not bear out the expected excess supply (whether before the effective date of the requested market-based rate authority, or thereafter), the PJM market monitor will inform the Commission and PJM, and as appropriate, may request that the regulation market be cost-based. Actual experience under market-based rates for regulation also will provide the best indication of whether the market performs competitively.

III. PJM Tariff and Operating Agreement Amendments

The implementation of market-based rates in the PJM West/South Regulation Zone requires no PJM Tariff or Operating Agreement amendments. The pertinent sections of these documents already provide that the regulation market will be cost-based only until the Commission grants market-based authority for the market.[51] Once such

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51 See, e.g., Operating Agreement, Schedule 1 § 1.10.1A(e) ("Regulation offered for any of the ECAR Control Zone(s) or MAIN Control Zone(s) shall be cost-based (including opportunity costs) until such time as market-based pricing is approved for regulation in such Control Zone."); see also id. at § 3.2.2(c). See also PJM South Filing, Operating Agreement Schedule 1, proposed Section 3.2.2(c).

authority is granted, the market rules will be the same for the regulation market in the PJM West/South Regulation Zone as for the regulation market in the MAAC Zone.

PJM, however, proposes to make one clarifying change to the PJM Tariff and Operating Agreement language setting forth the cost-based market rules for the regulation market in the PJM West/South Regulation Zone. PJM proposes to clarify that the offers for regulation in the PJM West/South Regulation Zone, until market-based authority is effective, are cost-based but may include an adder of seven dollars and fifty cents. This seven dollar and fifty cents component, while not currently specified in the PJM Tariff or Operating Agreement, is listed in the Cost Development Task Force ("CDTF") Manual as an approved component of cost-based regulation offers, and has been approved by the CDTF and PJM Board as a component of regulation costs. This margin is based on the PJM market monitor's calculations of actual observed margins included in regulation offers in the MAAC Zone.[52] The Commission previously approved a similar adder of seven dollars and fifty cents in cost-based offers for spinning reserves in the PJM market.[53]

Therefore, PJM proposes to clarify sections § 1.10.1A(e) and 3.2.2(c) of Schedule 1 of the Operating Agreement and Appendix to Attachment K of the PJM Tariff to read: "Regulation offered for any of the ECAR Control Zone(s) or MAIN Control Zone(s) shall be cost-based (including opportunity costs) *plus seven dollars and fifty cents* until

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52 Bowring Declaration ¶ 47.

53 See Operating Agreement Schedule 1 § 1.10.1A(j); PJM Interconnection, L.L.C., 101 FERC ¶ 61,115 (2002).

such time as market-based pricing is approved for regulation in such Control Zone"; and "A resource's Regulation offer for any of the ECAR Control Zone(s) or MAIN Control Zone(s) shall not exceed the cost of providing Regulation from such resource, *plus seven dollars and fifty cents*, unless and until market-based pricing is authorized for Regulation in such Control Zone," respectively.[54] As this is only a clarifying change, PJM requests an effective date of May 1, 2004, the date that ComEd was integrated into PJM and that such amount commenced being included in cost-based offers for regulation service. To further clarify, this request to explicitly acknowledge the seven dollar and fifty cents adder, is applicable only where regulation is priced under a cost-based structure. If the requested conversion of the PJM West/South Regulation Zone to a market-based structure is accepted, this decision will render the adder inapplicable going forward, unless the Commission were to direct PJM in the future to revert to cost-based compensation for regulation.

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54 Section 3.2.2(c) of the Appendix to Attachment K of the PJM Tariff also is revised to add the last sentence which is reflected in redline, but not in italics in the redline version of the sheets filed herein. This last sentence previously was added to section 3.2.2(c) in Schedule 1 of the Operating Agreement in Docket No. ER04-807 but inadvertently was omitted from section 3.2.2(c) of the Appendix to Attachment K of the PJM Tariff. The Commission accepted the sentence by letter order dated June 22, 2004. Appendix to Attachment K of the PJM Tariff and Schedule 1 of the Operating Agreement are intended to be identical. Therefore, in the Regulation Zone Filing, PJM added the omitted language to the PJM Tariff. The Regulation Zone Filing was accepted by the Commission with an effective date of October 1, 2004. To make section 3.2.2(c) of the Appendix to Attachment K of the PJM Tariff identical to the corresponding section in Schedule 1 of the Operating Agreement with the same effective date, PJM includes in this filing the language in section 3.2.2(c) of the Appendix to Attachment K of the PJM Tariff previously accepted by the Commission in the Regulation Zone Filing proceeding and requests an effective date of May 1, 2004 for the amendment.

IV. Waiver and Effective Date

PJM requests an effective date for the requested market-based rate authorization for the regulation market in the PJM West/South Regulation Zone of the date Virginia Power integrates into PJM, but no earlier than December 1, 2004 which is 60 days from the date of this filing. For the clarifying amendments to sections 1.10.1A(e) and 3.2.2(c) of Schedule 1 of the Operating Agreement and the Appendix to Attachment K of the PJM Tariff, PJM requests a waiver of the Commission's notice requirements to permit an effective date of May 1, 2004.

V. Request For Privileged Treatment

Pursuant to 18 C.F.R. § 388.112, PJM respectfully requests privileged treatment of portions of the transmittal letter, portions of the attached Declaration of Joseph E. Bowring and the entirety of Figures 1-7 attached 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.

In accordance with 18 C.F.R. § 388.112(b)(2)(iii), PJM submits one unredacted original transmittal letter, Declaration of Joseph E. Bowring and the attached Figures 1-7, and revised Operating Agreement and PJM Tariff sheets. The first page of the transmittal letter, the cover page of Exhibit 1 (Bowring Declaration and Figures 1-7) boldly indicate that PJM's submissions and each pertinent component thereof contains privileged information that should not be released. In addition, the information for which PJM seeks privileged treatment is identified within the unredacted original transmittal letter and Exhibit 1.

As further required by 18 C.F.R. § 388.112(b)(2)(i), PJM also submits fourteen copies of this transmittal letter, Declaration of Joseph E. Bowring and attached Figures 1-7, and revised Operating Agreement and PJM Tariff sheets that exclude all privileged material. The first page of the transmittal letter, the cover page of Exhibit 1 (Bowring Declaration and Figures 1-7), and each redacted page therein, boldly indicate that privileged material has been removed.

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
> Carrie L. Bumgarner
> Wright & Talisman, P.C.
> 1200 G Street, N.W., Suite 600
> Washington, D.C. 20005
> (202) 393-1200 (phone)
> (202) 393-1240 (fax)

VI. Documents Enclosed

PJM encloses one original, unredacted version and fourteen redacted copies, as explained above, of the following:

1. Transmittal Letter;
2. Exhibit A: Declaration of Joseph E. Bowring and attached Figures 1-7;
3. Exhibit B: Revised Operating Agreement and PJM Tariff sheets and redlined versions of same;

4. Federal Register Notice.

VII. Correspondence And Communications

Correspondence and communications with respect to this filing should be sent to, and PJM requests the Secretary to include on the official service list, the following:

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VIII. Service and Federal Register Notice

PJM has served a copy of this filing upon all PJM members and each state electric utility regulatory commission in the PJM region. A form of notice suitable for publication in the Federal Register is attached and is enclosed on diskette.

IX. Conclusion

For the reasons stated above, the Commission should grant market-based rate authority for the regulation market in the PJM West/South Regulation Zone and accept for filing the proposed PJM Tariff and Operating Agreement amendments.

Respectfully submitted,

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October 1, 2004

Attorneys for PJM Interconnection, L.L.C.

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EXHIBIT A

PUBLIC VERSION

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

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. This declaration presents the results of the analysis of the expected competitiveness of regulation markets in the newly redefined regulation markets within PJM Interconnection, L.L.C. ("PJM") undertaken by the PJM Market Monitoring Unit ("MMU"). The analysis includes regulation markets within the PJM footprint including two phases of market integration.

2. PJM markets will expand upon the integration of American Electric Power ("AEP"),[1] The Dayton Power and Light Company ("Dayton"), Virginia Electric Power Company ("Virginia Power") and Duquesne Light Company ("Duquesne"). AEP and Dayton are expected to be integrated on October 1, 2004, Virginia Power on November 1, 2004 and Duquesne on January 1, 2005.

Evolution of Market Definition for Regulation Markets in PJM Western Ancillary Service Area

3. The expected size and structure of regulation markets in the larger PJM footprint has evolved in significant ways since the spring of 2004. After integration is completed, PJM will operate markets in the North American Electric Reliability Council's ("NERC") Mid-American Interconnected Network ("MAIN"), East Central Area Reliability, ("ECAR"), Virginia and Carolina Reliability Region ("VACAR") and Mid-Atlantic Area Coordination Council ("MAAC") reliability regions. When originally planning the referenced integrations, PJM made an explicit decision to maintain the ancillary service requirements of each of the NERC reliability regions in which the PJM markets would operate. Specifically, PJM proposed grouping control zones with similar spinning and regulation requirements in ancillary service areas which would define ancillary service markets. The original

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[1] The American Electric Power Company operating companies are: Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, and Wheeling Power Company

proposal was to create four ancillary service areas: Commonwealth Edison Company (including Commonwealth Edison of Indiana) ("ComEd"); AEP, Dayton, Allegheny Power;[2] PJM; and Virginia Power. There would be a separate spinning and regulation market in each of these four areas. PJM took this approach in order to reflect the different, existing ancillary service requirements of the NERC regions, to minimize the operational impacts of the integrations and to permit PJM to gain experience with the expanded footprint before investigating the possibility of standardizing ancillary service requirements across the footprint and integrating the markets for these services.

4. After the May 27 stakeholder meeting, members requested that PJM investigate the possibility of combining the ancillary services markets (spinning reserve and regulation) for broader areas of the PJM footprint outside the PJM-Mid Atlantic area, coincident with the AEP integration, rather than maintaining separate ancillary markets by utility control area/zones or by NERC reliability region. PJM initiated discussions with the MAIN staff regarding the possibility of assigning physical resources in the AEP/Dayton/Allegheny Power zones to meet the regulation requirement for the ComEd zone, and received agreement from MAIN staff in early June that this approach would meet the MAIN requirements. Similar agreement was also received from representatives of VACAR and ECAR. Thus, a larger regulation market comprising parts of ECAR, MAIN and VACAR would be possible. However, with regard to spinning markets, it became clear that the necessary agreements were not in place, and could not be in place by October 1, 2004, to allow ECAR companies to provide reserve sharing response for MAIN events and vice versa. Therefore, it was determined that the ComEd (Northern Illinois Control Area or "NICA") and Virginia Power spinning reserve markets would therefore need to remain as separate markets.

5. In early July 2004, PJM proposed to its members that the spinning market definitions remain as initially proposed but that broader regulation markets be considered. In particular, PJM proposed that there could be two broad regulation markets, one consisting of PJM Mid-Atlantic and the other comprising all the other areas of PJM including Allegheny Power, ComEd, AEP, Dayton, Virginia Power and Duquesne. PJM noted that the broader definition of the regulation market could increase the efficiency of the market and minimize the chance that the regulation market will be cost based.

6. In late June, PJM staff was advised by counsel that the currently filed PJM Open Access Transmission Tariff ("PJM Tariff") language describing the ancillary service markets did not provide for the ability to operate the spinning reserve and regulation markets with different boundaries and did not provide for the operation of ancillary services markets across multiple NERC

[2] The Allegheny Power operating companies are: Monongahela Power Company, the Potomac Edison Company, and West Penn Power Company (collectively "Allegheny Power").

reliability regions. As a result, PJM began the process of developing alternate language that could be filed if the PJM stakeholders approved the broader regulation market definition. PJM also defined a process for stakeholder review and approval of any related filings with the Federal Energy Regulatory Commission ("FERC" or "Commission").

7. On September 1, 2004 PJM filed revisions to the PJM Tariff and Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. ("Operating Agreement"), among other things, to establish separate zones for the provision and pricing of regulation and spinning reserves. PJM requested Commission action prior to October 1, 2004 in order to permit an effective date of October 1, 2004 but otherwise requested an effective date of November 1, 2004. The filing defines separate regulation and spinning control zones as Regulation Zones and Spinning Reserve Zones. The proposed revisions to the PJM agreements would permit PJM to designate in the Manuals the exact combination of Control Zones comprising each such Regulation Zone and Spinning Reserve Zone. The filing also indicates that PJM would invoke the requested authority to designate the combination of the ComEd, AEP, Dayton, and Allegheny Power zones as one Regulation Zone while MAAC would remain a separate Regulation Zone..

8. In the September 1, 2004 filing PJM also stated that "PJM does not propose any changes to the tariff provisions that require cost-based regulation offers for regulation in the portions of the PJM region in MAIN and ECAR. However, the larger regulation market enabled by these changes may facilitate a subsequent request to the Commission for market-based rate authority for this service. PJM's market monitoring unit is considering this question, and PJM will report the results of that analysis when it is complete."

9. By letter order dated September 28, 2004, the Commission accepted the revisions to the PJM Tariff and Operating Agreement filed on September 1, 2004 in Docket No. ER04-1175.

10. The regulation market in PJM has been a price-based market since June 2000, with an offer cap of $100. The PJM market monitor filed an affidavit supporting a competitive regulation market in MAAC. The regulation market in Allegheny Power has been cost-based since the integration of Allegheny Power into PJM in April 2003 because the market structure is not consistent with a competitive outcome.

The Expected Competitiveness of Regulation Markets in PJM Western Ancillary Service Area

11. The provision of regulation constitutes a separate market as there are no good substitutes for the regulation product in the PJM market.

12. The provision of the regulation ancillary service, defined by FERC in Order No. 888,[3] is coordinated by PJM. NERC requires that PJM maintain regulating capability in order to match short-term deviations in system load. Regulation refers to the PJM control action that is performed to correct for load changes that may cause the power system to operate above or below 60 Hz.[4] The Capacity Resources assigned to meet the PJM Regulation Requirement must be capable of responding to the AR (Area Regulation) signal within five minutes and must increase or decrease their outputs at the Ramping Capability rates that are specified in the Offer Data that is submitted to PJM OI.[5] The regulation service supplied by individual generating units is: "The capability of a specific generating unit with appropriate telecommunications, control and response capability to increase or decrease its output in response to a regulating control signal."[6]

13. A Regulation Zone is defined as any of those one or more geographic areas, each consisting of a combination of one or more Control Zone(s) as designated by the Office of the Interconnection in the PJM Manuals, relevant to the provision of and requirement for, regulation service.[7] Regulation for each Regulation Zone shall be supplied from generators located within the metered electrical boundaries of such Regulation Zone.[8] Thus, the largest relevant geographic market for regulation service in the PJM West/South Regulation Zone is that entire zone. Imports of regulation are not possible. Suppliers in the relevant geographic market include all entities which own generating capacity in the market that have the required capability to provide regulation and pass PJM tests for regulation. The exact details of the operation of regulation over this broad area will not be clear until there is some experience operating the market. For example, it will be clear only after some real experience whether there are any locational regulation requirements within the broad PJM West/South Regulation Zone.

14. In reviewing the expected competitiveness of the proposed broad regulation markets, the MMU began with the basic facts of the market. The MMU has gathered data on regulation capability from the generators in the expanded PJM footprint and cross checked that data against available sources. The accuracy of the data has improved as generator reporting has improved. The resulting data set includes the available sources of regulation capability by

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3 Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 1991-1996 FERC Stats. & Regs., Regs. Preambles ¶ 31,036 (1996), order on reh'g, Order No. 888-A, 1996-2000 FERC Stats. & Regs., Regs. Preambles ¶ 31,048, order on reh'g, Order No. 888-B, 81 FERC ¶ 61,248 (1997), reh'g denied, Order No. 888-C, 82 FERC ¶ 61,046 (1998), aff'd in part and remanded in part sub nom. Transmission Access Policy Study Group v. FERC, 225 F.3d 667 (D.C. Cir. 2000), aff'd sub nom. New York v. FERC, 535 U.S. 1 (2002).

4 PJM Manual for Pre-Scheduling Operations, Manual M-10, page 26.

5 PJM Manual for Pre-Scheduling Operations, Manual M-10, page 27.

6 PJM Manual for Definitions and Acronyms, Manual M-35, page 53.

7 Operating Agreement, Section 1.38A.

8 Operating Agreement, Section 1.7.18 (a).

generation owner by area. The important caveat about the data is that it reflects capabilities reported by generation owners that have not yet been validated in actual market operation within PJM or been subjected to PJM tests of regulation capability.

15. The MMU analyzed two regulation market configurations based on the timing of market integrations. The first configuration included one regulation market comprising Allegheny Power, ComEd, AEP, Dayton and Duquesne. The second configuration added Virginia Power. We included Duquesne even though it will not be integrated until January 2005 to provide a view of the complete market. In addition, the regulation requirement of Duquesne is quite small and the overall impacts on the market analysis results are de minimis.

16. The MMU analyzed the regulation market configurations consistent with the approach defined in the Commission's April 14, 2004 Order. In that order the Commission adopted two indicative screens, a pivotal supplier analysis and a wholesale market share analysis. Failure of either screen creates a rebuttable presumption of market power. The delivered price test can be used to rebut or support the presumption of market power. The MMU has followed the logic of the April 14 Order in analyzing the expected competitiveness of the regulation market configurations.

17. Consistent with the April 14 Order, the MMU applied a pivotal supplier screen and a market share screen. The HHI was also calculated to provide context for the market share results. The Commission's Order does not specify an HHI test as part of the market share screen.

18. The MMU performed a pivotal supplier screen for each regulation market configuration using uncommitted regulation capacity.

19. For the pivotal supplier screen, uncommitted regulation capacity was calculated, following the April 12 Order, using the average of the daily peak demands for regulation during the month in which the annual peak load occurs. For the pivotal supplier screen, the wholesale market was defined to be the annual peak load less native load.

20. The relevant geographic area for the first pivotal supplier analysis is the first regulation market configuration comprising Allegheny Power, ComEd, AEP, Dayton and Duquesne.

21. The pivotal supplier analysis shows that no single supplier of regulation is pivotal in the first regulation market configuration. (See Figure 1.)

22. The MMU performed a wholesale market share analysis. Market shares based on a seasonal analysis of uncommitted regulation capacity were calculated for both regulation market configurations.

23. For the market share screen, uncommitted regulation capacity was calculated, following the April 12 Order, using total regulating capability and native load obligations based on the minimum peak demand by season. The four seasons included are summer (June/July/August), fall (September/October/November), winter (December/January/February) and spring (March/April/May). Uncommitted regulation capacity is calculated by subtracting the regulation requirement associated with the native load obligation on the minimum peak demand day, in a given season, from the regulation capability otherwise controlled by the participant and competing suppliers. The total uncommitted regulation capability for the relevant geographic area is the sum of the individual participant net regulation capabilities. Market shares are determined as the ratio of a participant's uncommitted regulation capability to the total uncommitted regulation capability for the area.

24. The relevant geographic area for the first market share analysis is the first regulation market configuration comprising Allegheny Power, ComEd, AEP, Dayton and Duquesne.

25. [redacted] Market HHIs range from 2477 in the summer to 2540 in the winter. (See Figure 2.)

26. The MMU concludes from these results that there is a rebuttable presumption of market power under the first regulation market configuration based on the 20 percent market share threshold specified in the April 14 Order. This is also consistent with the observed HHI levels. When the HHI is discussed in the context of the market share screen, the Commission notes that a market with an HHI greater than 1800 is considered highly concentrated.[9]

27. The relevant geographic area for the second market share analysis is the second regulation market configuration comprising Allegheny Power, ComEd, AEP, Dayton, Duquesne and Virginia Power. The second regulation market configuration is the first regulation market configuration plus Virginia Power.

28. Uncommitted regulation capacity was calculated in the same manner as for the first regulation market configuration. The pivotal supplier screen and the market share screen were applied in the same manner.

29. The pivotal supplier screen shows that no single supplier of regulation was pivotal in the second regulation market configuration. (See Figure 1.)

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[9] Order on Rehearing at par 96.

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30. [redacted] Market HHIs range from 2097 in the summer to 2130 in the winter. (See Figure 2.)

31. The MMU concludes from these results that there is a rebuttable presumption of market power under the second regulation market configuration based on the 20 percent market share threshold specified in the April 14 Order. This is also consistent with the observed HHI levels. In general, the results for the regulation market after the addition of Virginia Power show somewhat lower individual market shares for the dominant supplier and lower HHIs.

32. To help put these market structure results for the PJM West/South Regulation Zone in context, the MMU analyzed the market structure of the PJM Mid Atlantic regulation market. In the PJM MidAtlantic market, no supplier of regulation has a market share greater than 20 percent and the HHI is 1215. The ratio of excess regulation supply to peak regulation demand is 3.6 times.

33. An important factor mitigating the identified structural issues is the ratio of total regulation supply to maximum regulation demand. Based on the data received by the MMU, the total supply of regulation in the first regulation market configuration is 1,977 MW, the maximum demand for regulation is 628 MW and thus there is excess supply of 1,349 MW or 2.1 times the peak regulation demand. This aspect of market structure is at least partially captured in a pivotal supplier analysis. The greater the ratio of excess supply to demand, the lower the probability that any one supplier or small group of suppliers is pivotal. In addition, the details of the supply curve will help determine whether market power can be exercised. For example, the nature of the supply curve will determine if a single owner could unilaterally increase the market price by greater than 5 percent.

34. Another perspective on the ratio of supply to demand is provided by further review of the pivotal supplier results. The pivotal supplier screen comparing uncommitted regulation capability to the regulation requirement shows that, in the first regulation market configuration, the regulation owned by [redacted] is not required to meet the regulation requirement. In other words, no single supplier is pivotal and [redacted] could withhold their regulation capability and there would be adequate capability to meet the regulation requirement. (See Figure 1.)

35. The total supply of regulation in the second regulation configuration is 3,292 MW, the maximum demand for regulation is 784 MW and thus there is excess supply of 2,508 MW or 3.2 times the peak regulation demand.

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36. The pivotal supplier screen comparing uncommitted regulation capability to the regulation requirement shows that, in the second regulation market configuration, the regulation owned by [redacted] is not required to meet the regulation requirement. In other words, no single supplier is pivotal and [redacted] could withhold their regulation capability and there would be adequate capability to meet the regulation requirement. (See Figure 1.)

37. The MMU also applied a delivered price test for the proposed regulation markets. In this application of the delivered price test, available regulation was limited to regulation from units that were generating energy based on economic dispatch. The costs of acquiring regulation from non-operating units include the costs of start up and no load and are extremely high compared to the cost of regulation from operating units. The results of MMU GE MAPS simulation analyses were analyzed to determine the range of expected energy prices and thus the units that would be dispatched to deliver energy. The units that were economically dispatched and that have regulation capability were considered to be the available economic sources of regulation supply over a range of load conditions and corresponding market clearing prices in the energy market. The load was divided into four quartiles and the analysis was performed for each quartile in order to show the results over a range of load and related energy market and regulation market conditions. Pivotal supplier, market share and market concentration analyses were all performed as part of the delivered price test, consistent with the April 14 Order. (See Figures 3, 4, 5, and 6.)

38. The results of this delivered price test for the first regulation market configuration are similar to the results of the indicative market share screen reported above. The first case analyzed included all units that were economically dispatched for energy for the first three load quartiles.[10] In the case of the first regulation market configuration, for the bottom three quartiles of energy prices taken together, no company is pivotal. (See Figure 3.) In the case of the first regulation market configuration, for the bottom three quartiles of energy prices taken together, there is one company with a [redacted] market share and one company with a [redacted] market share. The HHI is 5637. (See Figure 5.)

39. The second case analyzed under the delivered price test included all units that were economically dispatched for energy to meet the load in the fourth or highest load quartile. In the case of the first regulation market configuration, at the load in the fourth quartile, no company is pivotal. For this case, there is

[10] The first three quartiles were grouped together as the energy market outcomes were quite similar for each quartile and thus the economically available regulation was comparable.

[redacted] The HHI is 3294.

40. The MMU concludes for the first regulation market configuration that the delivered price test does not provide evidence to rebut the results of the indicative screens. The delivered price test results are consistent with a finding of market power. The MMU also concludes that additional mitigating factors should be considered.

41. In the MMU's delivered price test, excess supply also serves as a mitigating factor for market power. For the first regulation market configuration, the ratio of excess supply to regulation demand was 2.2 times for the first three quartiles and 1.8 times including all the top quartile. (Figure 4.) The pivotal supplier test shows that the output of the [redacted] is not required to meet the regulation demand for the first three quartiles but that the output of the [redacted] is required to meet the regulation demand. When the fourth load quartile is included, the output of [redacted] is not required to meet the regulation demand and further the output of the [redacted] is not required to meet the regulation demand at this higher load level. (Figure 3.)

42. The results of the delivered price test for the second regulation configuration are also similar to the results of the indicative market share screen. In the case of the second regulation market configuration, for the bottom three quartiles of energy prices taken together, no company is pivotal. In the case of the second regulation market configuration, for the bottom three quartiles of loads taken together, there is [redacted] market shares. The HHI is 2870. Including the top quartile, no company is pivotal. Including the top quartile, there is one company with a [redacted] market share and one company with a [redacted] market share. The HHI is 2319. (Figure 3; Figure 6.)

43. The MMU concludes, based on the delivered price test for the second regulation market configuration, that the market passes the single pivotal supplier test, does not pass the market share test, does not pass the HHI test for loads consistent with the first three quartiles and does pass the HHI test for the higher load levels accounted for by including all four quartiles of the load distribution. The MMU concludes that the delivered price test does not provide evidence to rebut the results of the indicative screens. The MMU also concludes that additional mitigating factors should be considered.

44. Under the second regulation market configuration, the ratio of excess supply to regulation demand is high for all load levels. For the second regulation market configuration, the ratio of excess supply to regulation demand was 3.1

11 There is a significant change when the units required to serve the fourth quartile load are included because a high energy cost unit that is a significant supplier of regulation is economic only in the top quartile of energy market prices.

times for the first three quartiles and 2.7 times including all quartiles. (Figure 4.) The pivotal supplier test shows that the output of [redacted] is not required to meet the regulation demand associated with the load of the first three quartiles. For the higher loads associated with including all four quartiles, the output of [redacted] is not required to meet the associated regulation demand. (Figure 3.)

45. The data on available regulation supply, for the expanded footprint, included in this analysis was derived from a number of sources. Market participants were requested to submit regulation capability data to PJM 45 days prior to market integration. Where participant data was lacking, data derived from the GE MAPS simulation modeling of the expanded footprint was used. The regulation capability of the units in the expanded footprint has not been tested or checked by PJM. As noted below, the data needs to be validated with actual operating experience before it can be reasonably be relied upon to make a market power determination. Data on both the actual available regulation supply and the relative costs of that supply, accounting both for direct costs and opportunity costs, is needed to validate the analysis presented in this affidavit. That data will begin to be available upon the integration of AEP.

46. A large surplus of supply serves a role in mitigating the exercise of market power only if it actually exists. In this case, we will have the opportunity to review actual data and inform the Commission as to actual supply conditions prior to a Commission decision regarding a price-based regulation market after the integration of Virginia Power. This will include information on the actual levels of supply as well as relevant details about the supply curve. The time period between the integration of AEP and the integration of Virginia Power will be adequate to gather the relevant data. The experience of PJM in NICA indicates that all declared regulation capability may not exist. The actual regulation offered in NICA was only about half (55 percent) of the total regulation capability declared prior to the integration of NICA into PJM. The regulation market did not work as anticipated in NICA. While there is no reason to expect that experience to be repeated, it would be reasonable to have some actual experience with regulation offers in the expanded footprint before relying on the excess supply of regulation to mitigate the potential exercise of market power in the broader regulation markets. In addition to market power concerns, there is some uncertainty about exactly how the provision of regulation over such a large footprint will work.

47. Based on the above analysis, I recommend that the regulation market in the PJM West/South Regulation Zone continue to be cost based until the integration of Virginia Power. The PJM MMU will submit an updated analysis, data and recommendation to the Commission prior to the integration of Virginia Power indicating if the experience with the first market configuration demonstrates that the combined market may not pass the Commission's market power screens, including any additional, relevant mitigating factors. The existence of substantial excess supply and the nature of

the associated supply curve for regulation are such appropriate, potentially mitigating factors.

48. The efficiency consequences of maintaining a cost-based regulation market for a transition period are not likely to be significant because of the nature of the cost-based regulation market design. In the cost-based regulation market design, regulation suppliers submit offers subject to a cap of the cost of providing regulation plus a margin of $7.50. This margin is based on calculations of actual observed margins included in regulation offers in the price-based PJM (MAAC) regulation market. In the cost-based regulation market, PJM calculates, on an hour ahead basis, the opportunity costs for each unit offering to supply regulation. The total offer for each unit is then calculated to be the direct offer of the unit plus the opportunity cost for each unit. The inclusion of opportunity cost ensures that there will be a simultaneous optimization of the energy, regulation and spinning markets. Together, these offers constitute the supply curve for regulation. The market is cleared based on the fixed demand for regulation and the supply curve. Each regulating unit is paid the regulation market clearing price based on both the direct offer and the estimated opportunity cost. Every regulating unit is paid the higher of the regulation market clearing price or their offer plus the actual, real-time opportunity cost for each specific unit. Thus, there is substantial opportunity for regulating units to recover inframarginal rents in excess of the sum of their own direct costs and their own opportunity costs.

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

Executed this 30th day of September 2004.

Joseph E. Bowring

Joseph E. Bowring

FIGURE 1

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FIGURE 2

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FIGURE 3

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FIGURE 4

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FIGURE 5

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FIGURE 7

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EXHIBIT B

Operating Agreement Revisions

Non-Redline Version

K://PJM/Oarevs/OA Market Based Offers (clean).doc to supply the Operating Reserves of a Control Area outside the PJM Region. The foregoing offers:

i) Shall specify the generation resource and energy for each hour in the offer period;

ii) Shall specify the amounts and prices for the entire Operating Day for each resource component offered by the Market Seller to the Office of the Interconnection;

iii) If based on energy from a specific generating unit, may specify start-up and no-load fees equal to the specification of such fees for such unit on file with the Office of the Interconnection;

iv) Shall set forth any special conditions upon which the Market Seller proposes to supply a resource increment, including any curtailment rate specified in a bilateral contract for the output of the resource, or any cancellation fees;

v) May include a schedule of offers for prices and operating data contingent on acceptance by the deadline specified in this Schedule, with a second schedule applicable if accepted after the foregoing deadline;

vi) Shall constitute an offer to submit the resource increment to the Office of the Interconnection for scheduling and dispatch in accordance with the terms of the offer, which offer shall remain open through the Operating Day for which the offer is submitted;

vii) Shall be final as to the price or prices at which the Market Seller proposes to supply energy or other services to the PJM Interchange Energy Market, such price or prices being guaranteed by the Market Seller for the period extending through the end of the following Operating Day; and

viii) Shall not exceed an energy offer price of $1,000/megawatt-hour.

(e) A Market Seller that wishes to make a resource available to sell Regulation service shall submit an offer for Regulation that shall specify the MW of Regulation being offered, whether the Control Zone for which such regulation is offered, the price of the offer in dollars per MWh, and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer and the resource's opportunity costs. The price of the offer shall not exceed $100 per MWh in the case of regulation offered for the MAAC Control Zone. Regulation offered for any of the ECAR Control Zone(s), or MAIN Control Zone(s) shall be cost-based (including opportunity costs) plus seven dollars and fifty cents until such time as market-based pricing is approved for regulation in such Control Zone. Qualified Regulation capability must satisfy the verification tests specified in the PJM Manuals.

(f) Each Market Seller owning or controlling the output of a Capacity Resource shall submit a forecast of the availability of each such Capacity Resource for the next seven days. A Market Seller (i) may submit a non-binding forecast of the price at which it expects to offer a generation resource increment to the Office of the Interconnection over the next seven days, and (ii) shall submit a binding offer for energy, along with start-up and no-load fees, if any, for the next seven days or part thereof, for any generation resource with minimum notification or start-up requirement greater than 24 hours.

3.2.2 Control Zone Regulation.

(a) Each Internal Market Buyer that is a Load Serving Entity in a Control Zone shall have an hourly Regulation objective equal to its *pro rata* share of the Regulation requirements of such Control Zone for the hour, based on the Market Buyer's total load in such Control Zone for the hour. An Internal Market Buyer that does not meet its hourly Regulation obligation shall be charged for Regulation dispatched by the Office of the Interconnection to meet such obligation at the Regulation market-clearing price determined in accordance with paragraph (c) of this Section, plus the amounts, if any, described in paragraph (f) of this Section.

(b) A Generating Market Buyer supplying Regulation in a Control Zone at the direction of the Office of the Interconnection in excess of its hourly Regulation obligation shall be credited for each increment of such Regulation at the higher of (i) the Regulation market-clearing price in such Control Zone or (ii) the sum of the regulation offer and the unit-specific opportunity cost of the resource supplying the increment of Regulation, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(c) The Regulation market-clearing price in each Control Zone shall be determined at a time to be determined by the Office of the Interconnection which shall be no earlier than the day before the Operating Day and the market-clearing price each hour shall be equal to the highest sum of a resource's Regulation offer plus its estimated unit-specific opportunity costs from among the resources selected to provide Regulation. A resource's Regulation offer for any of the ECAR Control Zone(s) or MAIN Control Zone(s) shall not exceed the cost of providing Regulation from such resource, plus seven dollars and fifty cents, unless and until market-based pricing is authorized for Regulation in such Control Zone.

(d) In determining the Regulation market-clearing price in each Control Zone, the estimated unit-specific opportunity costs of a resource offering to sell Regulation each hour shall be equal to the product of (i) the deviation of the set point of the resource that is expected to be required in order to provide Regulation from the resource's expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the resource and the offer price for energy from the resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market.

(e) In determining the credit under subsection (b) to a Generating Market Buyer selected to provide Regulation in a Control Zone and that actively follows the Office of the Interconnection's Regulation signals and instructions, the unit-specific opportunity cost of a resource shall be determined for each hour that the Office of the Interconnection requires a resource to provide Regulation and shall be equal to the product of (i) the deviation of the resource's output necessary to follow the Office of the Interconnection's Regulation signals from the resource's expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the resource and the offer price for energy from the resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market.

(f) Any amounts credited for Regulation in an hour in excess of the Regulation market-clearing price in that hour shall be allocated and charged to each Internal Market Buyer in a Control Zone that does not meet its hourly Regulation obligation in proportion to its purchases of Regulation in such Control Zone in megawatt-hours during that hour.

Operating Agreement Revisions

Redline Version

K://PJM/Oarevs/OA Market Based Offers (redline).doc to supply the Operating Reserves of a Control Area outside the PJM Region. The foregoing offers:

i) Shall specify the generation resource and energy for each hour in the offer period;

ii) Shall specify the amounts and prices for the entire Operating Day for each resource component offered by the Market Seller to the Office of the Interconnection;

iii) If based on energy from a specific generating unit, may specify start-up and no-load fees equal to the specification of such fees for such unit on file with the Office of the Interconnection;

iv) Shall set forth any special conditions upon which the Market Seller proposes to supply a resource increment, including any curtailment rate specified in a bilateral contract for the output of the resource, or any cancellation fees;

v) May include a schedule of offers for prices and operating data contingent on acceptance by the deadline specified in this Schedule, with a second schedule applicable if accepted after the foregoing deadline;

vi) Shall constitute an offer to submit the resource increment to the Office of the Interconnection for scheduling and dispatch in accordance with the terms of the offer, which offer shall remain open through the Operating Day for which the offer is submitted;

vii) Shall be final as to the price or prices at which the Market Seller proposes to supply energy or other services to the PJM Interchange Energy Market, such price or prices being guaranteed by the Market Seller for the period extending through the end of the following Operating Day; and

viii) Shall not exceed an energy offer price of $1,000/megawatt-hour.

(e) A Market Seller that wishes to make a resource available to sell Regulation service shall submit an offer for Regulation that shall specify the MW of Regulation being offered, whether the Control Zone for which such regulation is offered, the price of the offer in dollars per MWh, and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer and the resource's opportunity costs. The price of the offer shall not exceed $100 per MWh in the case of regulation offered for the MAAC Control Zone. Regulation offered for any of the ECAR Control Zone(s), or MAIN Control Zone(s) shall be cost-based (including opportunity costs) plus seven dollars and fifty cents until such time as market-based pricing is approved for regulation in such Control Zone. Qualified Regulation capability must satisfy the verification tests specified in the PJM Manuals.

(f) Each Market Seller owning or controlling the output of a Capacity Resource shall submit a forecast of the availability of each such Capacity Resource for the next seven days. A Market Seller (i) may submit a non-binding forecast of the price at which it expects to offer a generation resource increment to the Office of the Interconnection over the next seven days, and (ii) shall submit a binding offer for energy, along with start-up and no-load fees, if any, for the next seven days or part thereof, for any generation resource with minimum notification or start-up requirement greater than 24 hours.

3.2.2 Control Zone Regulation.

(a) Each Internal Market Buyer that is a Load Serving Entity in a Control Zone shall have an hourly Regulation objective equal to its *pro rata* share of the Regulation requirements of such Control Zone for the hour, based on the Market Buyer's total load in such Control Zone for the hour. An Internal Market Buyer that does not meet its hourly Regulation obligation shall be charged for Regulation dispatched by the Office of the Interconnection to meet such obligation at the Regulation market-clearing price determined in accordance with paragraph (c) of this Section, plus the amounts, if any, described in paragraph (f) of this Section.

(b) A Generating Market Buyer supplying Regulation in a Control Zone at the direction of the Office of the Interconnection in excess of its hourly Regulation obligation shall be credited for each increment of such Regulation at the higher of (i) the Regulation market-clearing price in such Control Zone or (ii) the sum of the regulation offer and the unit-specific opportunity cost of the resource supplying the increment of Regulation, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(c) The Regulation market-clearing price in each Control Zone shall be determined at a time to be determined by the Office of the Interconnection which shall be no earlier than the day before the Operating Day and the market-clearing price each hour shall be equal to the highest sum of a resource's Regulation offer plus its estimated unit-specific opportunity costs from among the resources selected to provide Regulation. A resource's Regulation offer for any of the ECAR Control Zone(s) or MAIN Control Zone(s) shall not exceed the cost of providing Regulation from such resource, plus seven dollars and fifty cents, unless and until market-based pricing is authorized for Regulation in such Control Zone.

(d) In determining the Regulation market-clearing price in each Control Zone, the estimated unit-specific opportunity costs of a resource offering to sell Regulation each hour shall be equal to the product of (i) the deviation of the set point of the resource that is expected to be required in order to provide Regulation from the resource's expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the resource and the offer price for energy from the resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market.

(e) In determining the credit under subsection (b) to a Generating Market Buyer selected to provide Regulation in a Control Zone and that actively follows the Office of the Interconnection's Regulation signals and instructions, the unit-specific opportunity cost of a resource shall be determined for each hour that the Office of the Interconnection requires a resource to provide Regulation and shall be equal to the product of (i) the deviation of the resource's output necessary to follow the Office of the Interconnection's Regulation signals from the resource's expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the resource and the offer price for energy from the resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market.

(f) Any amounts credited for Regulation in an hour in excess of the Regulation market-clearing price in that hour shall be allocated and charged to each Internal Market Buyer in a Control Zone that does not meet its hourly Regulation obligation in proportion to its purchases of Regulation in such Control Zone in megawatt-hours during that hour.

Tariff Revisions

Non-Redline Version

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$100 per MWh in the case of regulation offered for the MAAC Control Zone. Regulation offered for any of the ECAR Control Zone(s) or MAIN Control Zone(s) shall be cost-based (including opportunity costs) plus seven dollars and fifty cents until such time as market-based pricing is approved for regulation in such Control Zone. Qualified Regulation capability must satisfy the verification tests specified in the PJM Manuals.

(f) Each Market Seller owning or controlling the output of a Capacity Resource shall submit a forecast of the availability of each such Capacity Resource for the next seven days. A Market Seller (i) may submit a non-binding forecast of the price at which it expects to offer a generation resource increment to the Office of the Interconnection over the next seven days, and (ii) shall submit a binding offer for energy, along with start-up and no-load fees, if any, for the next seven days or part thereof, for any generation resource with minimum notification or start-up requirement greater than 24 hours.

(g) Each offer by a Market Seller of a Capacity Resource shall remain in effect for subsequent Operating Days until superseded or canceled.

(h) The Office of the Interconnection shall post on the PJM Open Access Same-time Information System the total hourly loads scheduled in the Day-ahead Energy Market, as well as, its estimate of the combined hourly load of the Market Buyers for the next four days, and peak load forecasts for an additional three days.

(i) All Market Participants may submit Increment Bids and/or Decrement Bids that apply to the Day-ahead Energy Market only. Such bids must comply with the requirements set forth in the PJM Manuals and must specify amount, location and price, if any, at which the Market Participant desires to purchase or sell energy in the Day-ahead Energy Market. The Office of the Interconnection may require that a market participant shall not submit in excess of 3000 bid/offer segments in the Day-ahead Energy Market, when the Office of the Interconnection determines that such limit is required to avoid or mitigate significant system performance problems related to bid/offer volume. Notice of the need to impose such limit shall be provided prior to 10:00 a.m. EPT on the day that the Day-ahead Energy Market will clear. For purposes of this provision, a bid/offer segment is each pairing of price and megawatt quantity submitted as part of an Increment Bid or Decrement Bid.

(j) A Market Seller that wishes to make a resource available to sell Spinning Reserve shall submit an offer for Spinning Reserve that shall specify the megawatt of Spinning Reserve being offered, the price of the offer in dollars per megawatt hour, and such other information specified

3.2.2 Control Zone Regulation.

(a) Each Internal Market Buyer that is a Load Serving Entity in a Control Zone shall have an hourly Regulation objective equal to its *pro rata* share of the Regulation requirements of such Control Zone for the hour, based on the Market Buyer's total load in such Control Zone for the hour. An Internal Market Buyer that does not meet its hourly Regulation obligation shall be charged for Regulation dispatched by the Office of the Interconnection to meet such obligation at the Regulation market-clearing price determined in accordance with paragraph (c) of this section, plus the amounts, if any, described in paragraph (f) of this section.

(b) A Generating Market Buyer supplying Regulation in a Control Zone at the direction of the Office of the Interconnection in excess of its hourly Regulation obligation shall be credited for each increment of such Regulation at the higher of (i) the Regulation market-clearing price in such Control Zone or (ii) the sum of the regulation offer and the unit-specific opportunity cost of the resource supplying the increment of Regulation, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(c) The Regulation market-clearing price in each Control Zone shall be determined at a time to be determined by the Office of the Interconnection which shall be no earlier than the day before the Operating Day and the market-clearing price each hour shall be equal to the highest sum of a resource's Regulation offer plus its estimated unit-specific opportunity costs from among the resources selected to provide Regulation. A resource's Regulation offer for any of the Regulation Zone(s) in the PJM West Region shall not exceed the cost of providing Regulation from such resource, plus seven dollars and fifty cents, unless and until market-based pricing is authorized for Regulation in such Regulation Zone.

(d) In determining the Regulation market-clearing price in the PJM Control Area, the estimated unit-specific opportunity costs of a resource offering to sell Regulation each hour shall be equal to the product of (i) the deviation of the set point of the resource that is expected to be required in order to provide Regulation from the resource's expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the resource and the offer price for energy from the resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market.

(e) In determining the credit under subsection (b) to a Generating Market Buyer selected to provide Regulation in a Control Zone and that actively follows the Office of the Interconnection's Regulation signals and instructions, the unit-specific opportunity cost of a resource shall be determined for each hour that the Office of the Interconnection requires a resource to provide Regulation and shall be equal to the product of (i) the deviation of the resource's

Tariff Revisions

Redline Version

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NOTICE OF FILING

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.) Docket No. ER04-___ -

NOTICE OF FILING

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Take notice that on October 1, 2004, PJM Interconnection, L.L.C. ("PJM") filed for a change in rates to permit market-based offers in the expanded PJM market for regulation service in the portion of the PJM region covered by the geographic territories of Allegheny Power, American Electric Power Company ("AEP"), Commonwealth Edison Company (including Commonwealth Edison Company of Indiana) ("ComEd"), The Dayton Power and Light Company ("Dayton"), Dusquesne Light Company ("Dusquesne"), and Virginia Electric Power Company ("Virginia Power").

Copies of the filing were served upon all PJM Members including Allegheny Power, AEP, ComEd, Dayton, Dusquesne, and Virginia Power, and each state electric utility regulatory commission in the PJM region.

Any person desiring to intervene or to protest this filing must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. Such notices, motions, or protests must be filed on or before the comment date. Anyone filing a motion to intervene or protest must serve a copy of that document on the Applicant. On or before the comment date, it is not necessary to serve motions to intervene or protests on persons other than the Applicant.

The Commission encourages electronic submission of protests and interventions in lieu of paper using the "eFiling" link at http://www.ferc.gov. Persons unable to file electronically should submit an original and 14 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426.

This filing is accessible on-line at http://www.ferc.gov, using the "eLibrary" link and is available for review in the Commission's Public Reference Room in Washington, D.C. There is an "eSubscription" link on the web site that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please email FERCOnlineSupport@ferc.gov, or call (866) 208-3676 (toll free). For TTY, call (202) 502-8659.

Comment Date: 5:00 pm Eastern Time on (insert date).

Magalie R. Salas
Secretary