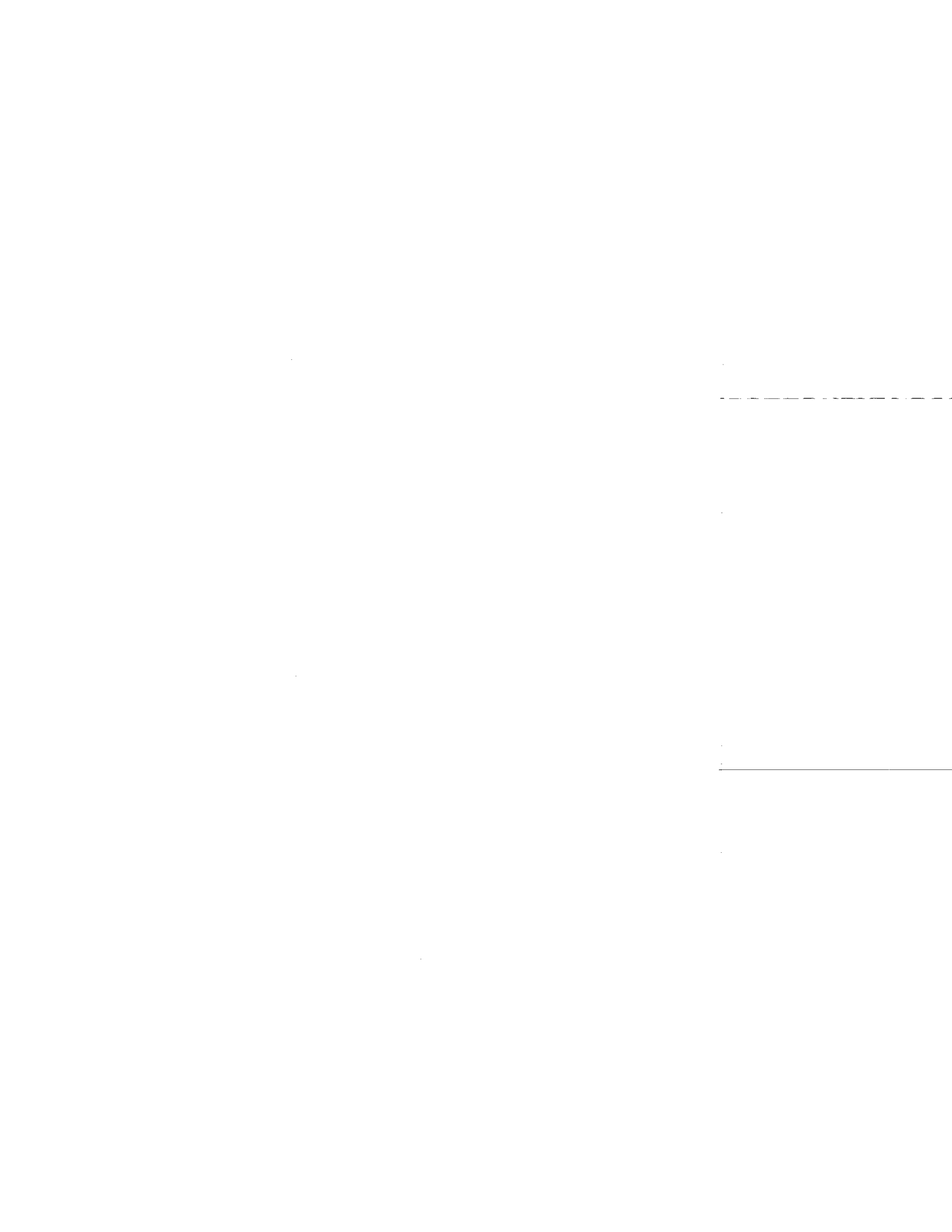


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## **SUBMITTED COMMITTEE REPORTS**

**As a general policy, the Energy Bar Association does not take a position in published Committee Reports on substantive issues that are the subject of pending litigation.**



# REPORT OF THE ELECTRIC UTILITY REGULATION COMMITTEE

## I. INTRODUCTION

In 2004, the Federal Energy Regulatory Commission (Commission or FERC) continued to focus on the development of Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs). This report discusses developments concerning Midwest Independent Transmission System Operator, Inc. (MISO), PJM Interconnection, LLC (PJM), and the Southwest Power Pool (SPP). The report also summarizes developments in New England, California refund proceedings, the FERC's approaches to evaluating market-based rate applications, the Commission's rulemaking on generator interconnection rules, the standard for reviewing affiliate transactions, and a major bankruptcy proceeding involving a jurisdictional dispute.

## II. RTO ISSUES – PJM, MISO, SPP

### A. MISO

#### 1. MISO's Transmission and Energy Markets Tariff

On December 20, 2001, the FERC granted MISO's status as an RTO (RTO Order).<sup>1</sup> In the RTO Order, the Commission directed MISO to commence efforts to develop a market-based congestion management system for Day 2 operations, in accordance with Order No. 2000.<sup>2</sup>

On March 31, 2004, MISO filed a modified Transmission and Energy Markets Tariff (TEMT) proposal. MISO had originally filed its TEMT proposal, which included provisions for Day-Ahead and Real-Time Energy Markets and Financial Transmission Rights (FTRs), on July 25, 2003. That proposal was widely protested by stakeholders claiming that it was incomplete and immature. In response, MISO requested and received Commission authorization to withdraw the TEMT proposal.<sup>3</sup>

On August 6, 2004, the Commission conditionally accepted MISO's modified TEMT proposal (TEMT Order).<sup>4</sup> The TEMT Order set forth the terms and conditions required to implement a security-constrained centralized dispatch,

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1. *Midwest Indep. Transmission Sys. Operator, Inc.*, 97 F.E.R.C. ¶ 61,326 (2001), *reh'g denied*, 103 F.E.R.C. ¶ 61,169 (2003).

2. Order No. 2000, *Reg. Transmission Orgs.*, [Regs. Preambles 1996–2000] F.E.R.C. STATS & REGS. ¶ 31,089 (2000), 65 Fed. Reg. 809 (2000) (to be codified at 18 C.F.R. pt. 35), *order on reh'g*, Order No. 2000-A, *Reg. Transmission Orgs.*, [Regs. Preambles 1996–2000] F.E.R.C. STATS. & REGS. ¶ 31,092 (2000), 65 Fed. Reg. 12,088 (2000) (to be codified at 18 C.F.R. pt. 35), *aff'd*, Pub. Util. Dist. No. 1 of Snohomish County, Wash. v. FERC, 272 F.3d 607 (D.C. Cir. 2001) [hereinafter Order No. 2000].

3. *Midwest Indep. Transmission Sys. Operator, Inc.*, 105 F.E.R.C. ¶ 61,145 (2003) (instructing the Midwest ISO to include the following elements in a future TEMT filing: (1) a *pro forma* System Support Resource Agreement; (2) a marginal loss crediting mechanism; (3) an initial FTR allocation methodology; (4) creditworthiness standards; and (5) market mitigation measures), *reh'g dismissed*, 105 F.E.R.C. ¶ 61,272 (2003).

4. See *Midwest Indep. Transmission Sys. Operator, Inc.*, 108 F.E.R.C. ¶ 61,163 (2004), *order on reh'g*, 109 F.E.R.C. ¶ 61,157 (2004).

market-based congestion management program, and energy spot markets, including Day-Ahead and Real-Time Energy Markets, locational marginal pricing (LMP), and a market for FTRs.<sup>5</sup>

The TEMT Order also accepted MISO's proposed System Supply Resources (SSR) program, the goal of which is to provide a construct for compensating generation resources that are uneconomic but needed for reliability.<sup>6</sup> Under the SSR program, MISO will determine whether a generation unit should be granted SSR status pursuant to information provided by a market participant accompanying a notice of retirement, extended shutdown or disconnection.<sup>7</sup> Subsequently, the SSR unit and MISO will enter into an agreement providing for recovery of certain going-forward costs, offset by expected payments for resource adequacy and revenues from energy market transactions that must be filed with the Commission.<sup>8</sup> The Commission found that the SSR program is a "reasonable backstop measure" to assure reliability in MISO markets,<sup>9</sup> noting that inadequate reactive power contributed to the blackout on August 14, 2003.<sup>10</sup> SSR units will be used primarily for reactive power.<sup>11</sup> The Commission also determined that such costs are appropriately assigned to market participants serving load in the affected control areas.<sup>12</sup>

Finally, the TEMT Order directed MISO to provide additional customer protections during the transition to a fully functioning energy market, due to the fact that MISO – unlike ISO-NE, PJM, and NYISO – did not have a history of centralized power pool dispatch.<sup>13</sup> At the time the TEMT Order was issued, the implementation date for MISO's transmission and energy markets was scheduled for March 1, 2005 (May 26 Order).<sup>14</sup>

Subsequently, the Commission issued an order on rehearing on the TEMT Order (Rehearing Order).<sup>15</sup> The Rehearing Order denied rehearing on most key issues, generally reaffirmed the TEMT Order, and provided clarification on certain issues.

On December 20, 2004, the Commission addressed issues raised in MISO's compliance filing in accordance with the TEMT Order (Order on Compliance Filing).<sup>16</sup> The Order on Compliance Filing found that, with respect to the "issues most critical to market start-up" – cost-based bidding, FTR allocation, FTR congestion hedging, automatic and control area mitigation, the SSR program,

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5. *See generally id.*

6. 108 F.E.R.C. ¶ 61,163 at 61,967.

7. *Id.*

8. 108 F.E.R.C. ¶ 61,163 at 61,967.

9. *Id.*

10. *Midwest Indep. Transmission Sys. Operator, Inc.*, 108 F.E.R.C. ¶ 61,163 (2004).

11. *Id.* at 61,967.

12. 108 F.E.R.C. ¶ 61,163 at 61,967.

13. *Id.* at 61,916, 61,920–29.

14. 108 F.E.R.C. ¶ 61,163 at 61,915; *see also Midwest Indep. Transmission Sys. Operator, Inc.*, 107 F.E.R.C. ¶ 61,191, 61,789 (2004).

15. *See Midwest Indep. Transmission Sys. Operator, Inc.*, 109 F.E.R.C. ¶ 61,157 (2004).

16. *Midwest Indep. Transmission Sys. Operator, Inc.*, 109 F.E.R.C. ¶ 61,285 (2004).

creditworthiness standards, and seams resolution – MISO was in compliance with the TEMT Order.<sup>17</sup>

## 2. Treatment of Grandfathered Agreements

MISO's modified TEMT proposal, filed with the Commission on March 31, 2004, raised the issue of how to integrate approximately 300 grandfathered agreements (GFAs) into MISO markets. MISO expressed concern that "carving out" the GFAs could compromise reliability and produce significant cost consequences for other market participants. In response, the Commission commenced an investigation pursuant to section 206 of the Federal Power Act (FPA) in order to gain a better understanding of whether GFAs could be integrated into MISO energy markets; whether, and to what extent, transmission owners should be responsible for the costs related to fulfilling the terms of the GFAs; and whether, and to what extent, the GFAs should be modified.<sup>18</sup>

In a September 15, 2004 order, the Commission presented the findings of its investigation into GFAs and outlined how GFAs will be treated in MISO and FTR markets (GFA Order).<sup>19</sup> The Commission's investigation revealed that approximately 23% (25,000 megawatts (MW)) of total MISO load would be receiving transmission service under 229 GFAs as of March 1, 2005.<sup>20</sup> Of that 23%, approximately 9% of total MISO load voluntarily elected to participate in MISO's energy markets, and another 4.5%, whose GFAs were subject to the just and reasonable standard of review, would also participate as a result of contract modification.<sup>21</sup> According to the Commission, the remaining 9.6% of MISO load could be "carved out" without compromising the reliable and efficient operation of MISO's energy and FTR markets.<sup>22</sup>

The GFA Order also determined that Schedule 16 (FTR service) charges should apply to GFA transactions "to the extent that those transactions are subject to the Midwest ISO Energy Markets and GFA parties have nominated FTRs for those transactions or otherwise receive a hedge in the Day-Ahead Energy Markets for such transactions."<sup>23</sup> With respect to Schedule 17 (Energy Market Service) charges, the GFA Order stated that such charges should apply equally to GFA and non-GFA transactions.<sup>24</sup> Regarding responsibility for Schedule 16 and 17 charges, the GFA Order held that for GFAs participating in MISO energy markets Schedule 16 and 17 charges would be the responsibility of the GFA Responsible Entity.<sup>25</sup> For "carved-out" GFAs, Schedule 17 charges will be the responsibility of the Transmission Owner or Independent

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17. *Id.* at 62,344.

18. 107 F.E.R.C. ¶ 61,191, at 61,785.

19. *See generally* *Midwest Indep. Transmission Sys. Operator, Inc.*, 108 F.E.R.C. ¶ 61,236 (2004).

20. *Id.* at 62,275.

21. 108 F.E.R.C. ¶ 61,236, at 62,275.

22. *Id.*

23. 108 F.E.R.C. ¶ 61,236, at 62,275.

24. *Id.*

25. *Midwest Indep. Transmission Sys. Operator, Inc.*, 108 F.E.R.C. ¶ 61,236, 62,275 (2004).

Transmission Company Participant taking service under the MISO Tariff to meet its transmission service obligations under the GFA.<sup>26</sup>

### 3. Joint Operating Agreement

During 2004, MISO and PJM entered into a Joint Operating Agreement (MISO-PJM JOA) (conditionally accepted by the Commission in a March 18, 2004 order<sup>27</sup>) intended to facilitate a joint and common market that includes both MISO and PJM. The MISO-PJM JOA provides for “information sharing, coordinated congestion management, coordinated [calculation of] TTC, ATC and AFC determinations, coordinated emergency procedures, and joint [system] expansion planning . . . .”<sup>28</sup> The Commission required certain modifications to the MISO-PJM JOA. These included requiring MISO and PJM to make the process for identifying coordinated flowgates more transparent and directing revisions to clarify the status of rollover and reservation priority granted to transmission service customers with terms of more than one year under the PJM and MISO Open Access Transmission Tariffs (OATTs).<sup>29</sup> In its Order on Clarification and Denying Rehearing, the Commission clarified that under the MISO-PJM JOA, the use of historic network native load to allocate available flowgate capacity between the RTOs on a forward-looking basis for new transmission requests (rather than selling the remaining capacity on a first-come, first-served basis) is appropriate.<sup>30</sup>

#### B. PJM – Integration of AEP/PURPA Proceeding

In 2004, PJM continued to expand with several of the former Alliance Companies becoming “New PJM Companies.” The Commission approved Commonwealth Edison Company’s integration into PJM effective May 1, 2004,<sup>31</sup> and conditionally approved the integration of Virginia Electric and Power Company into PJM.<sup>32</sup> The proposed integration of American Electric Power Company (AEP), however, developed into a jurisdictional battle.

In 2000, the Commission approved the merger of AEP and Central and South West Corporation (CSW) on the condition that AEP join an independent transmission organization.<sup>33</sup> AEP initially proposed to participate in the ill-fated Alliance RTO and subsequently committed to join PJM (November 25 Order).<sup>34</sup> AEP then sought the requisite state authorizations to join PJM. Two states in

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26. *Id.*

27. *Midwest Indep. Transmission Sys. Operator, Inc.*, 106 F.E.R.C. ¶ 61,251 (2004).

28. *Id.* at 61,893.

29. 106 F.E.R.C. ¶ 61,251, at 61,893.

30. *Midwest Indep. Transmission Sys. Operator, Inc.*, 109 F.E.R.C. ¶ 61,166, 61,803 (2004).

31. *PJM Interconnection, L.L.C.*, 107 F.E.R.C. ¶ 61,087 (2004).

32. *PJM Interconnection, L.L.C.*, 109 F.E.R.C. ¶ 61,012 (2004).

33. *See Am. Elec. Power Co.*, 90 F.E.R.C. ¶ 61,242 (2000), *order on reh'g*, 91 F.E.R.C. ¶ 61,129 (2000) (affirming in relevant part), *appeal denied sub nom. Wabash Valley Power Ass'n v. FERC*, 268 F.3d 1105 (D.C. Cir. 2001) (denying petition for review). Section 203 of the Federal Power Act, 16 U.S.C. § 824b (2000), provides the Commission broad authority to impose conditions, e.g., on mergers between utilities subject to the Commission’s jurisdiction. The Commission typically justifies such conditions on the basis that they are intended to remedy some competitive hazards associated with a particular transaction.

34. *New PJM Cos.*, 105 F.E.R.C. ¶ 61,251, 62,309 (2003).

which AEP subsidiaries do business, Kentucky and Virginia, resisted. The Kentucky Public Service Commission (KPSC) disapproved AEP's application,<sup>35</sup> and the Virginia legislature enacted a law that, in the short-term, effectively barred Virginia utilities from joining a RTO (although it actually *required* Virginia utilities to join a RTO after a certain statutory date).<sup>36</sup> Responding to what the FERC contended was the states' refusal to permit AEP to transfer control of its transmission facilities to PJM, the FERC issued an order proposing to invoke, for the first time, section 205(a) of the Public Utility Regulatory Policies Act of 1978 (PURPA) in order to override the states.<sup>37</sup>

In pertinent part, section 205(a) of the PURPA authorizes the Commission to preempt state law, rule, or regulation in the event it:

prohibits or prevents the voluntary coordination of electric utilities . . . designed to obtain economical utilization of facilities and resources . . . . No such exemption may be granted if the Commission finds that such provision of State law, or rule or regulation . . . is designed to protect public health, safety, or welfare . . . .<sup>38</sup>

As required by the statute, the FERC initiated a hearing to examine whether these conditions for preemptive authority under PURPA section 205(a) were met.<sup>39</sup> In an initial decision issued on March 24, 2004, the administrative law judge assigned to the case found that the requisites for preemption were met (Initial Decision).<sup>40</sup> The parties subsequently reached a settlement as to the Kentucky portion of the matter. Thus, when the matter was set for Commission action, the FERC issued a pair of orders to close the hearing—one to consider the Kentucky settlement (Kentucky Settlement Order)<sup>41</sup> and the other addressing the Initial Decision as to Virginia (Opinion No. 472).<sup>42</sup>

In the first order, the FERC approved a settlement resolving Kentucky's objections to AEP joining PJM.<sup>43</sup> The settlement provides for the participation in PJM of AEP's Kentucky operating company, but it reserves the KPSC's right to review AEP's cost of service, affirms that AEP's participation in PJM's energy markets is voluntary, and provides that AEP's load would not be curtailed if a transmission system emergency occurs unless PJM has exercised all other options.<sup>44</sup> The FERC approved the settlement without modification.<sup>45</sup>

In the companion order, Opinion No. 472, the FERC affirmed on all grounds the decision of the administrative law judge, finding that the FERC had properly invoked its authority under the PURPA to override Virginia law.<sup>46</sup> This

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35. *Id.* at 62,311.

36. 105 F.E.R.C. ¶ 61,251, at 62,310.

37. The Commission cited the Virginia Restructuring Act and an order of the KPSC as obstacles to AEP's integration into PJM. *See id.* at 62,325–27 (discussing applicable Kentucky and Virginia law and regulatory actions, concluding that they have served as obstacles to AEP's integration into PJM).

38. 16 U.S.C. § 824a-1(a) (2000).

39. 105 F.E.R.C. ¶ 61,251, at 62,327–28.

40. *New PJM Cos.*, 106 F.E.R.C. ¶ 63,029, 65,351 (2004).

41. *New PJM Cos.*, 107 F.E.R.C. ¶ 61,272 (2004).

42. *New PJM Cos.*, 107 F.E.R.C. ¶ 61,271 (2004).

43. 107 F.E.R.C. ¶ 61,272, at 62,230.

44. *Id.* at 62,231–33.

45. 107 F.E.R.C. ¶ 61,272, at 62,228.

46. 107 F.E.R.C. ¶ 61,271, at 62,211.

was the case, the FERC found, because AEP's commitment to join PJM would constitute a voluntary coordination of electric utilities that is designed to achieve the economical utilization of facilities.<sup>47</sup> The FERC found that the Virginia laws preventing AEP from joining PJM were not exempt from a PURPA override since those laws were motivated primarily by economic protectionism, rather than the legitimate exercise of the state's police powers relating to health, safety, and welfare.<sup>48</sup>

Virginia sought stays of Opinion No. 472 both at the Commission (which the FERC initially denied) and in the U.S. Court of Appeals for the District of Columbia Circuit. Before the court acted, however, on July 27, 2004, AEP, the Virginia State Corporation Commission (VSCC) staff, the Virginia Attorney General's office, and others, entered into a stipulation which ultimately led to the VSCC's approval, on August 30, 2004, of AEP's application to transfer functional control of its transmission facilities to PJM.<sup>49</sup> PJM agreed in the stipulation to certain limits on its curtailment procedures. PJM will: (1) not direct AEP to curtail Virginia customers, retail or wholesale, for whom AEP has a generation capacity obligation; (2) not direct AEP to curtail load in Virginia unless all other remedies have been exhausted; and (3) not deviate from any curtailment protocol except in extraordinary circumstances.

In light of the settlement, on September 9, 2004, the VSCC, joined by the Louisiana Public Service Commission, asked the FERC to vacate and dismiss as moot Opinion No. 472 on the ground that the goal of that order – achieving the transfer of functional control to PJM of AEP's transmission assets in Virginia – had already been approved by the VSCC.<sup>50</sup> In exchange, the state regulators proposed to withdraw their request for rehearing of Opinion No. 472 and terminate their related efforts in the appellate courts.<sup>51</sup>

A coalition of southern and western states – which had from the outset supported the FERC's efforts to override Virginia and Kentucky's objections to AEP's integration into PJM (most of which are not home to an RTO- or ISO-member utility) – endorsed the two states' proposed trade.<sup>52</sup> In contrast, proponents of the FERC overriding the state opposition to RTOs, stated that the FERC was under no obligation to vacate Opinion No. 472 but that they would not oppose the FERC's doing so provided it does not disrupt AEP's integration into PJM.<sup>53</sup> The FERC staff opposed vacatur primarily on the ground that, even though the matter was moot, the proceeding set important markers for how the Commission will view, and if necessary, use, its authority under section 205(a)

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47. *Id.* at 62,212 (finding that AEP's joining PJM would constitute "coordination" within the meaning of the PURPA section 205(a)); 107 F.E.R.C. ¶ 61,271, at 62,213 (finding the coordination to be "voluntary"); *Id.* at 62,214–15 (finding proof of economic benefit to be unnecessary, as the statute only requires that the coordination be "designed" to achieve economic utilization of facilities, but noting anyway that AEP's joining PJM likely would have such an effect).

48. 107 F.E.R.C. ¶ 61,271, 62,219–21 (2004).

49. *Virginia ex rel. State Corp. Comm'n*, 235 P.U.R. 4th 327 (VaPUC Aug. 30, 2004).

50. *New PJM Cos.*, 110 F.E.R.C. ¶ 61,009, 61,023 (2005).

51. *Id.*

52. 110 F.E.R.C. ¶ 61,009, at 61,023.

53. *Id.*



of the PURPA.<sup>54</sup> On January 7, 2005, the Commission denied the request to vacate Opinion No. 472.<sup>55</sup>

### C. *Southwest Power Pool*

In a series of orders issued during 2004, the SPP was conditionally declared a RTO, subject to a few remaining modifications. The first such order, issued on February 10, 2004, approved the RTO proposal subject to satisfying certain of the Commission's remaining concerns (February Order).<sup>56</sup> Two successive sets of compliance filings followed—one responding to the February Order and the second to a July 2, 2004, order wherein the Commission delineated areas in which SPP was still falling short of the Commission's vision (July Order).<sup>57</sup> Finally, on October 1, 2004, the Commission issued a pair of orders, one on SPP's second compliance filing (October Compliance Order),<sup>58</sup> and the other addressing the requests for rehearing of the July Order (October Rehearing Order).<sup>59</sup> These orders found that SPP covered virtually all the ground necessary to attain RTO status.<sup>60</sup>

#### 1. Governance

In its February Order, the Commission rejected SPP's plan to install an independent board *after* issuance of a final order recognizing SPP's status as an RTO—holding that the independent board was a *prerequisite* to gaining final RTO status which SPP attained by May.<sup>61</sup> The Commission also directed SPP to balance the achieve representation on the Members Committee – particularly by adding end-user representatives.<sup>62</sup> SPP met this directive by adding two seats—one for large end users, another for smaller ones (below 1 MW demand).<sup>63</sup> In addition, the Commission required SPP to alter a rule preventing the independent board from making decisions without concurrence of the Members Committee.<sup>64</sup>

#### 2. Scope and Seams Reduction

While SPP's own footprint is not inconsiderable,<sup>65</sup> the Commission required SPP to expand its effective reach by entering into seams reduction

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54. 110 F.E.R.C. ¶ 61,009, at 61,023.

55. *Id.* at 61,024.

56. *Southwest Power Pool, Inc.*, 106 F.E.R.C. ¶ 61,110 (2004).

57. *Southwest Power Pool, Inc.*, 108 F.E.R.C. ¶ 61,003 (2004).

58. *Southwest Power Pool, Inc.*, 109 F.E.R.C. ¶ 61,009 (2004).

59. *Southwest Power Pool, Inc.*, 109 F.E.R.C. ¶ 61,010 (2004).

60. 109 F.E.R.C. ¶ 61,009; 109 F.E.R.C. ¶ 61,010.

61. 106 F.E.R.C. ¶ 61,110, at 61,374.

62. *Id.* at 61,374–75.

63. As a result, SPP would have four seats for IOUs, four for electric co-ops, two for municipal utilities, three for independent power/marketers, one for the government (federal/state) public power sector, and one for "alternative power" interests. These seats are in addition to the end user seats. *Southwest Power Pool, Inc.*, 108 F.E.R.C. ¶ 61,003, 61,017 (2004).

64. 106 F.E.R.C. ¶ 61,110, at 61,375.

65. It includes all or portions of eight states and eleven transmission systems (of which six are jurisdictional) and multiple control areas, while serving four million ultimate customers. *Id.* at 61,369, 61,375.

agreements with neighboring systems, including MISO.<sup>66</sup> In its July Order, the Commission concluded that SPP's efforts documented in its compliance filing – which included a Memorandum of Understanding and a report that it was making strides towards a framework for achieving a JOA – lacked the definitiveness and urgency the Commission required.<sup>67</sup> The Commission ordered SPP to file a seams agreement as part of its next compliance filing,<sup>68</sup> and SPP in its next compliance filing, satisfied the Commission's concern.<sup>69</sup> The Commission also addressed some intervenor objections that it was premature to direct SPP to join the MISO/PJM joint and common market, because a key part of SPP's phased approach to market design was that it would not incorporate energy markets unless and until the participants (including state agencies) conducted cost/benefit analyses. The FERC clarified in the October Rehearing Order that, in this regard, it was not attempting to preempt the cost-benefit analysis stage and that, if SPP did not proceed with energy markets, it still should participate in the MISO/PJM joint and common market in a limited "market-to-non-market" mode.<sup>70</sup>

### 3. Operational Authority

The Commission found in the July Order that SPP's attempts to clarify its operational authority by filing: (1) a white paper that described its functions<sup>71</sup> and its relations to the control area operators; and (2) a system map depicting transmission lines over which it would exercise operational control were too ambiguous. As a corrective measure, the FERC required SPP to: (1) incorporate the substance of the white paper into its Members Agreement; and (2) file a list of specific transmission facilities over which it would exercise operational control.<sup>72</sup> The Commission also ruled, in the October Rehearing Order, that it would not, at that time, require SPP to consolidate its separate eighteen control areas, but it did direct SPP to conduct a study of the feasibility of such consolidation and report back in one year.<sup>73</sup>

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66. *Southwest Power Pool, Inc.*, 106 F.E.R.C. ¶ 61,110, 61,377 (2004).

67. 108 F.E.R.C. ¶ 61,003, at 61,020.

68. *Id.*

69. *Southwest Power Pool, Inc.*, 109 F.E.R.C. ¶ 61,009, 61,032 (2004). In the October Rehearing Order, the Commission also affirmed that transmission owners could not withdraw from SPP absent FERC authority, based on the Commission's authority under section 205 of the FPA. *Southwest Power Pool, Inc.*, 109 F.E.R.C. ¶ 61,010, 61,041–43 (2004).

70. 109 F.E.R.C. ¶ 61,010, at 61,041.

71. 108 F.E.R.C. ¶ 61,003, at 61,022. The Commission instructed SPP to follow the NERC's recently developed matrix of functions in spelling out the roles of all participants in operating and ensuring reliability of the system. 106 F.E.R.C. ¶ 61,110, at 61,379–80.

72. 108 F.E.R.C. ¶ 61,003, at 61,022.

73. 109 F.E.R.C. ¶ 61,010, at 61,045. The Commission rejected an intervenor argument that this study should not be entrusted to SPP, on the ground that it would be inclined to preserve the status quo. The FERC ruled that SPP was sufficiently independent to answer this concern. *Id.*

#### 4. Conforming Grandfathered and Bundled Retail Service Obligations to RTO OATT Provisions

In the October Rehearing Order, the FERC ruled that its requirement that all transmission services within SPP conform to the non-rate terms and conditions of the SPP OATT was applicable to bundled retail load,<sup>74</sup> although the FERC was not “explicitly” addressing the terms and conditions of bundled retail service. In its second compliance filing (following the July Order), SPP excepted unbundled transmission service to a federal agency (the Southwest Power Administration) and to other holders of unbundled transmission contracts from the rule of applying non-rate provisions of the OATT to all transmission service. However, in its October Compliance Order, the Commission found that there could be no exceptions to that rule.<sup>75</sup> In a similar vein, in the October Rehearing Order, the Commission held that all loads (including bundled retail loads) should bear a share of the administrative costs of the SPP RTO.<sup>76</sup>

#### D. Elimination of Regional Through and Out Rates in MISO and PJM

In a May 21, 2003 order, the Commission directed PJM and MISO to make a joint filing explaining the seams issues they faced, how and when the issues would be resolved, and which entity would take leadership of the process to address such issues.<sup>77</sup> This directive was based on a report by the MISO Independent Market Monitor, which noted that generation located in and dispatched by one RTO can have an impact on flowgates located in the other RTO, leading to inefficient pricing and dispatch, as well as excessive uplift payments.<sup>78</sup> According to the Commission, “generators in one RTO could strategically dispatch to cause congestion in the other RTO and then offer transactions to relieve that congestion.”<sup>79</sup> The Commission concluded that such problems could be mitigated by coordination between the RTOs.<sup>80</sup>

The consideration of seams issues between PJM and MISO focused on the assessment by both RTOs of regional “through and out rates” on transmission transactions crossing its systems, resulting in multiple charges from a single transaction. The Commission found that such rate-pancaking across RTO borders was an impediment to the development of a common market between MISO and PJM.<sup>81</sup> The Commission ordered MISO and PJM, in a July 23, 2003 order,<sup>82</sup> to eliminate through and out rates for new transactions sinking in the

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74. 109 F.E.R.C. ¶ 61,010, at 61,046. The Commission based this result on the requirement that under Order No. 2000 that the RTO must be the “sole provider” of transmission service. *Id.*

75. *Southwest Power Pool, Inc.*, 109 F.E.R.C. ¶ 61,009, 61,033–34 (2004).

76. 109 F.E.R.C. ¶ 61,010, at 61,046.

77. *Midwest Indep. Transmission Sys. Operator, Inc.*, 103 F.E.R.C. ¶ 61,210, 61,795 (2003).

78. *Id.*

79. 103 F.E.R.C. ¶ 61,210, at 61,795.

80. *Id.*

81. Importantly, the Commission began its review of through and out rates in the MISO and PJM footprints following its order in *Alliance Cos.*, 100 F.E.R.C. ¶ 61,137 (2002), where it accepted the choices of the various transmission owners participating in the Alliance RTO proposal to join either the Midwest ISO or PJM.

82. *Midwest Indep. Transmission Sys. Operator, Inc.*, 104 F.E.R.C. ¶ 61,105 (2003).

MISO/PJM footprint, effective November 1, 2003. The Commission concluded that the through and out rates “perpetuate seams that prevent the realization of more efficient and competitive electricity markets in the region, and thus violate a central tenet of the Commission’s RTO policy.”<sup>83</sup>

In November of 2003, the Commission issued two additional orders on the through and out rates. First, in an order on rehearing, the Commission extended the date by which the rates should be eliminated to April 1, 2004, and also made further rulings concerning the use of a transitional mechanism to address concerns regarding lost revenues and possible cost shifting between customers of the two RTOs after the through and out rates are eliminated.<sup>84</sup> In its initial order eliminating the through and out rates, the Commission determined that it was not obligated to establish a transition mechanism to account for revenue losses. Furthermore, the Commission stated that certain proposed seams elimination cost assignment (SECA) proposals could, if properly structured, be a reasonable transition mechanism and invited parties to file such mechanisms under section 205 of the FPA.<sup>85</sup> On rehearing, the Commission found that a transitional rate design to recover lost revenues (through a non-bypassable surcharge) was necessary for a two-year period and required that RTOs submit compliance filings under section 206 of the FPA containing a transition surcharge to be implemented simultaneously with the elimination of the through and out rates.<sup>86</sup> The Commission also made certain findings relative to the appropriate design of a proposed SECA mechanism, including finding that SECA charges could be imposed on a sub-zonal basis and that the charges should be based on the most recent through and out rate revenue data available.<sup>87</sup> The Commission denied a request by certain Wisconsin and Michigan customers to continue to pay through and out rates instead of being subject to a SECA mechanism.<sup>88</sup> Further, the order clarified that existing contracts containing through and out rates, transactions that sink outside the MISO/PJM footprint, and transactions that sink in one control area but serve load in another are all exempt from SECA charges.<sup>89</sup>

In the second November 2003 order, the Commission held that the through and out rates charged by the former Alliance Companies who had not joined MISO or PJM were unjust and unreasonable with respect to transactions sinking in the MISO/PJM footprint.<sup>90</sup> The order required that such rates be eliminated effective April 1, 2004, the date on which the MISO/PJM through and out rates were to be eliminated. The Commission reasoned that given the Alliance Companies’ unique location “in the heart of the [MISO/PJM] region,” their imposition of through and out rates “leave the region riddled with seams that deny the RTO members the benefits of more efficient and competitive electricity

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83. *Id.* at 61,355.

84. *Midwest Indep. Transmission Sys. Operator, Inc.*, 105 F.E.R.C. ¶ 61,212 (2003).

85. 104 F.E.R.C. ¶ 61,105 at 61,360–61.

86. 105 F.E.R.C. ¶ 61,212, at 62,116.

87. *Id.* at 62,112–13, 62,115.

88. 105 F.E.R.C. 61,212, at 62,116.

89. *Id.* at 62,102–03, 62,114.

90. *Ameren Servs. Co.*, 105 F.E.R.C. ¶ 61,216 (2003).

markets.”<sup>91</sup> The Commission directed the subject Alliance Companies to submit compliance filings containing a transition charge.<sup>92</sup>

Following these orders, MISO and PJM (and other parties) entered into settlement negotiations to develop a SECA transitional charge proposal. In March 2004, the Commission accepted an agreement joined or supported by most of the parties to the settlement negotiations to retain the through and out rates until December 1, 2004, to establish “going-forward principles,” and continue negotiations to reach a final pricing solution that would eliminate seams in the MISO/PJM region.<sup>93</sup> In the event the parties could not reach a final solution and file it pursuant to section 205 of the FPA, the agreement provided that the parties would file multiple solutions for the Commission’s consideration, to be effective December 1, 2004.

The parties failed to reach agreement on a final pricing solution, and in November 2004, the Commission ordered the adoption of one of several SECA proposals.<sup>94</sup> Specifically, to eliminate seams and rate-pancaking within the PJM/MISO footprint, the Commission ordered the adoption of a license plate rate design, coupled with a transition mechanism and reevaluation of the rates after a fixed period ending January 31, 2008.<sup>95</sup> As the transition mechanism, the Commission ordered the adoption of the SECA mechanism it outlined in the first of the two November 2003 orders.<sup>96</sup> Numerous parties sought rehearing of the Commission’s order.

### III. DEVELOPMENTS IN NEW ENGLAND

#### A. Market Mitigation

In the last two years, the New England wholesale electricity market has undergone significant change and development. In the New England Power Pool (NEPOOL) new market rules were adopted, provisions governing cost allocation for transmission upgrades were developed and approved, the installed capacity market underwent significant change, and ISO-NE became a Commission-approved RTO.

In March of 2004, ISO-NE filed a proposed locational ICAP mechanism (LICAP) in compliance with the Commission’s directives. In a series of 2003 orders, the Commission had rejected several reliability must-run (RMR) agreements entered into between ISO-NE and generating facilities that the ISO determined were necessary to maintain reliability, but that were receiving insufficient revenues from the market to remain in operation.<sup>97</sup> In one of those

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91. *Id.* at 62,134.

92. 105 F.E.R.C. ¶ 61,216, at 62,138.

93. *Midwest Indep. Transmission Sys. Operator, Inc.*, 106 F.E.R.C. ¶ 61,262 (2004).

94. *See Midwest Indep. Transmission Sys. Operator, Inc.*, 109 F.E.R.C. ¶ 61,168 (2004).

95. *Id.* at 61,819–20.

96. *See Midwest Indep. Transmission Sys. Operator, Inc.*, 105 F.E.R.C. ¶ 61,212 (2003).

97. *See, e.g., Devon Power LLC*, 103 F.E.R.C. ¶ 61,082 (2003), *order on reh’g*, 104 F.E.R.C. ¶ 61,123 (2003); *PPL Wallingford Energy LLC*, 103 F.E.R.C. ¶ 61,185 (2003), *order on reh’g*, 105 F.E.R.C. ¶ 61,324 (2003). ISO-NE noted in these proceedings its concern that the current market rules and mitigation procedures may not allow generators in congested areas to recover their costs, necessitating RMR contracts.

orders, the Commission announced its concerns regarding the widespread use of RMR agreements, and declared that such contracts or other out-of-market arrangements “should be a last resort.”<sup>98</sup> The Commission stated, “the proliferation of these agreements is not in the best interest of the competitive market,” because they “suppress market-clearing prices, increase uplift payments, and make it difficult for new generators to profitably enter the market.”<sup>99</sup> In that order, the Commission also found that to remedy the market deficiencies creating revenue problems for generators in congested areas, a location-specific capacity requirement or deliverability requirement should be implemented.<sup>100</sup> The order directed ISO-NE to file a mechanism implementing either requirement by March 1, 2004, for implementation by June 1, 2004.<sup>101</sup> In the interim, the Commission directed ISO-NE to implement temporary revised bidding and mitigation rules for certain peaking generating units in congestion areas (called Peaking Unit Safe Harbor, or PUSH, bidding), to allow the units to increase their bids and recover their costs through the market.<sup>102</sup>

In a June 2004 order, the Commission accepted the general framework of ISO-NE’s proposal.<sup>103</sup> Specifically, the Commission accepted ISO-NE’s choice to implement a LICAP mechanism (as opposed to a deliverability requirement) with separate ICAP requirements in various regions of New England,<sup>104</sup> and its proposal to use a demand curve (similar to that used in the New York ISO) to set the amount and price of ICAP within each region.<sup>105</sup> The Commission set the details of ISO-NE’s proposal for hearing before an administrative law judge, including the specific parameters of the demand curve, the method of calculating the amount of capacity which may be imported into a region for purposes of satisfying the ICAP requirement, and the proper amount and allocation of capacity transfer rights.<sup>106</sup> The Commission also delayed the implementation of the LICAP mechanism to January 1, 2006, to allow for additional time to complete infrastructure upgrades, and stated that the PUSH mechanism, along with RMR contracts where needed, would continue to be in place in the interim period before implementation.<sup>107</sup> Additionally, the Commission addressed the

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98. 103 F.E.R.C. ¶ 61,082, at 61,270.

99. *Id.*

100. 103 F.E.R.C. ¶ 61,082, at 61,270.

101. *Id.* at 61,271.

102. *Devon Power LLC*, 103 F.E.R.C. ¶ 61,082, 61,270 (2003).

103. *Devon Power LLC*, 107 F.E.R.C. ¶ 61,240 (2004), *order on reh'g*, 109 F.E.R.C. ¶ 61,154 (2004). Prior to issuing this order, but after ISO-NE made its LICAP filing, the Commission accepted for filing RMR agreements between ISO-NE and various units owned by NRG, to be in place until the LICAP mechanism is implemented. See *Devon Power LLC*, 106 F.E.R.C. ¶ 61,264 (2004). The Commission found that RMR treatment for these units for a limited term was appropriate, because they were uniquely situated in the severely constrained Southwest Connecticut area, were older, less efficient units, and were not performing well under the PUSH rules. *Id.* at 61,954–55.

104. Under the ICAP market rules existing at the date of ISO-NE’s filing, load-serving entities could procure resources to meet their ICAP requirement from any unit in New England, even if that unit’s output could not be physically delivered to the load-serving entity’s region. Under the LICAP proposal, ICAP must be procured from the load-serving entity’s region.

105. 107 F.E.R.C. ¶ 61,240, at 62,027.

106. *Id.* at 62,031–34.

107. 107 F.E.R.C. ¶ 61,240, at 62,034–35.

four ICAP regions proposed by ISO-NE in its filing, which were Connecticut, northeastern Massachusetts/Boston, Maine, and the “Rest of Pool.” Specifically, the Commission instituted a paper hearing and investigation, pursuant to section 206 of the FPA, to determine whether southwestern Connecticut should also be an ICAP region.<sup>108</sup> In an order issued in November 2004, the Commission ordered ISO-NE to include southwestern Connecticut as a fifth ICAP region.<sup>109</sup>

### *B. Allocation of Costs for Transmission Upgrades*

In December of 2003, the Commission issued an order approving a set of Transmission Cost Allocation (TCA) amendments to the NEPOOL Tariff and Restated NEPOOL Agreement and dismissing a complaint asking the Commission to reject the TCA amendments and adopt an alternate allocation methodology.<sup>110</sup> Under the TCA amendments approved by the Commission, and included in Schedule 12 of the NEPOOL Tariff, a combination of participant funding and regional cost support is utilized to allocate transmission upgrade costs. Generally, costs incurred for projects that provide regional reliability or economic benefits are allocated across the entire region, while the cost of projects providing only local benefits, merchant transmission projects, and generator interconnection projects are allocated to the participants.<sup>111</sup> These “localized costs” not recoverable from the entire region can include costs incurred within a broader project that provides reliability or economic benefits to the entire region (making it eligible for regional cost support) that are deemed excessive.<sup>112</sup>

### *C. ISO-NE Approved as RTO*

In 2004, ISO-NE became the United States’ fourth Commission-approved RTO. In a March 2004 order, the Commission gave its conditional approval to a proposal submitted by ISO-NE and several transmission owners to convert the current ISO structure in New England to a RTO.<sup>113</sup> When the new entity (ISO-NE RTO) begins operations, it will be the provider of regional transmission service in the New England region currently served by ISO-NE, it will exercise operational authority over the transmission owner’s facilities (in a single control area) under a detailed Transmission Operator Agreement, and it will serve as the administrator of the New England wholesale energy market.<sup>114</sup> In contrast to the current ISO structure, the new ISO-NE RTO will have greater rights to make section 205 filings with the Commission in “emergency” situations (including

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108. *Id.* at 62,030–31.

109. *Devon Power LLC*, 109 F.E.R.C. ¶ 61,156 (2004).

110. *New Eng. Power Pool-ISO New Eng., Inc.*, 105 F.E.R.C. ¶ 61,300 (2003); *order on reh’g*, 109 F.E.R.C. ¶ 61,252 (2004). The complaint set forth an alternative cost-allocation proposal, developed by a coalition of governmental entities, consumer advocates, and generators, which relied more heavily on “beneficiary funding,” as opposed to regional cost support.

111. *Id.* at 62,450.

112. *See generally* 105 F.E.R.C. ¶ 61,300, at 62,450; *see also generally Lynch*, 107 F.E.R.C. ¶ 61,242, 62,042 (2004).

113. *ISO New Eng., Inc.*, 106 F.E.R.C. ¶ 61,280 (2004).

114. *Id.* at 62,023.

filings to address efficiency, competitiveness, and reliability), and (after a five-year moratorium) in cases where it determines that a change in rate design proposed by a transmission owner is inconsistent with another existing design for rates or charge for transmission service.<sup>115</sup> In its March order the Commission, in addition to finding (with conditions) that the ISO-NE RTO proposal meets the required minimum characteristics and functions in Order No. 2003, also determined that the transmission owners and ISO-NE may withdraw from the Restated NEPOOL Agreement and file the RTO proposal under section 205.<sup>116</sup>

Additionally, the Commission accepted the proposal to include a fifty basis point incentive adder in the return on equity component of ISO-NE RTO's transmission rates for regional network service, finding it as an appropriate reward for the transmission owner's voluntary action to establish the RTO and transfer operational control of its transmission facilities.<sup>117</sup> The Commission denied the fifty basis point incentive adder for transmission provided under the local service schedule, however, finding that the same rationale did not apply, and set for hearing a proposed 100 basis point incentive adder for investment in new transmission facilities. Finally, as noted above, the March order placed certain conditions on the approval of ISO-NE RTO, including: (1) ordering the submission of a seams resolution agreement with the New York ISO; (2) ordering the submission of an agreement with NEPOOL addressing how ISO-NE RTO may acquire certain reversionary interests in ISO-NE held by NEPOOL; and (3) requiring certain revisions to the ISO-NE RTO agreements with the transmission owners.

In a November 2004 order on rehearing, compliance, and a partial settlement, the Commission accepted a settlement addressing NEPOOL's reversionary interests in ISO-NE.<sup>118</sup> Under that settlement, NEPOOL would transfer its reversionary interests, by way of a bill of sale, to ISO-NE RTO operations on the date ISO-NE RTO commenced operations.<sup>119</sup> That order also addressed seams issues between the new RTO and the New York ISO. While finding that the parties had made progress, and accepting filings by the New York ISO and NEPOOL to eliminate through and out service charges between their respective systems,<sup>120</sup> the Commission required further action on seams issues, including a filing that included a proposal for resolving each remaining seams issue and implementation dates for the Seams Resolution Agreement.<sup>121</sup>

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115. 106 F.E.R.C. ¶ 61,280, at 62,030-33.

116. *Id.* at 62,025-26.

117. 106 F.E.R.C. ¶ 61,280, at 61,579-80.

118. *ISO New Eng. Inc.*, 109 F.E.R.C. ¶ 61,147 (2004).

119. *Id.* at 61,574.

120. *See* 109 F.E.R.C. ¶ 61,147, at 61,579-80.

121. *Id.* at 61,580.



## IV. ACTIVITIES IN CALIFORNIA

A. *Proceedings Before the Federal Energy Regulatory Commission*

## 1. California Refund Proceeding

The California Refund Proceeding remains active. On May 12, 2004, the Commission issued an Order on Request for Rehearing and Clarification (Refund Rehearing Order) of its two California refund orders issued on October 16, 2003 (Refund Rehearing Order).<sup>122</sup> The Commission issued this order to clarify its method for calculating refunds. The Refund Rehearing Order responded to numerous questions posed by parties and intervenors in their requests for rehearing and clarification.<sup>123</sup> The Commission also addressed many procedural and technical issues in various orders throughout the year. The Commission staff held a Technical Conference on October 4, 2004, in which CAISO took the lead on technical issues. In addition, the Commission has approved several settlements in the California refund proceeding throughout the year.

## 2. Settlements

On July 2, 2004, the Commission approved a settlement with conditions that resolved issues concerning Williams Energy Marketing & Trading Company<sup>124</sup> and several of the California public utilities. On October 25, 2004, the Commission approved a settlement with conditions between Dynegy and various complainants.<sup>125</sup> On December 7, 2004, the Commission approved a settlement with conditions that resolved many of the claims against Duke Energy.<sup>126</sup> These settlements provided other parties to the proceeding an opportunity to join the settlements and avoid the costs of litigation.

## 3. Show Cause Orders

In response to the June 2003 issuance of the Commission's Gaming Order (Gaming Order)<sup>127</sup> and Partnership Gaming Order (Partnership Gaming Order),<sup>128</sup> many of the parties identified as possible gamers filed requests for rehearing or clarification. The Commission issued an order on January 22, 2004, denying rehearing and declining to broaden the scope of the show cause orders (Order Denying Rehearing).<sup>129</sup> The Commission Staff communicated with the parties, and analyzed the information provided to determine whether a party had

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122. *San Diego Gas & Elec. Co.*, 107 F.E.R.C. ¶ 61,165 (2004).

123. Also on May 12, the Commission issued an Order Addressing Fuel Cost Allowances Issues in the same proceeding. *Id.*

124. *San Diego Gas & Elec. Co.*, 108 F.E.R.C. ¶ 61,002 (2004).

125. *San Diego Gas & Elec. Co.*, 109 F.E.R.C. ¶ 61,071 (2004).

126. *San Diego Gas & Elec. Co.*, 109 F.E.R.C. ¶ 61,257 (2004).

127. *Am. Elec. Power Serv. Corp.*, 103 F.E.R.C. ¶ 61,345 (2003), *reh'g denied*, 106 F.E.R.C. ¶ 61,020 (2004).

128. *Enron Power Mktg. Inc.*, 103 F.E.R.C. ¶ 61,346 (2003), *reh'g denied*, 106 F.E.R.C. ¶ 61,020 (2004).

129. *Am. Elec. Power Serv. Corp.*, 106 F.E.R.C. ¶ 61,020 (2004).

likely been a gamer. When the Commission Staff became convinced that there was no evidence of gaming, it filed a Motion to Dismiss for those particular parties. On January 22, 2004, the Commission addressed these requests.

#### 4. Fact-Finding Investigation

The Commission issued an order on rehearing on May 5, 2004, addressing requests for rehearing of several orders in its Fact-Finding Investigation.<sup>130</sup> Specifically, this order responded to the various requests relating to the release of data received by the Commission as part of its ongoing investigations into energy prices in the West. The Commission had received a significant amount of personal personnel information from Enron that initially was made public. The Commission also received data as a result of its June 2003 order. The Commission continued to work with parties to evaluate the data and to determine what should be made public. The Commission concluded that: (1) personal personnel information should not be released because it serves no public interest; (2) the Commission should honor the United States Attorney's request to keep certain information confidential during the ongoing criminal investigations; and (3) investigative information should be kept non-public during the active investigation to protect the integrity of the process.

#### B. Opinions Issued by the United States Court of Appeals for the Ninth Circuit

##### 1. Refunds for Violations of Reporting Requirements<sup>131</sup>

On September 9, 2004, the Ninth Circuit granted the State of California's petition for review of the FERC order declining to order refunds for violations of FERC reporting requirements during the California energy crisis.<sup>132</sup> California claimed that the FERC did not properly administer its market-based rate tariffs when the Commission concluded it lacked the authority to order \$2.8 billion in retroactive refunds. The Commission argued that it was precluded from ordering retroactive refunds in these cases. The court agreed with California, concluding that the FERC abused its administrative discretion under the circumstances, and noting that the FERC has recognized in other cases that it has the authority to impose retroactive refunds for section 205 violations. The court remanded the case for further proceedings.<sup>133</sup> Intervenors to the proceeding filed a petition for panel rehearing and a petition for rehearing en banc on October 25, 2004; the court had not yet responded to the request for rehearing as of December 31, 2004.

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130. *Fact-Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices*, 107 F.E.R.C. ¶ 61,108 (2004).

131. *California ex rel. Lockyer v. FERC*, 383 F.3d 1006 (9th Cir. 2004).

132. *Id.*

133. The Commission did not take any action on the remand in 2004.

## 2. Preemption of State Law<sup>134</sup>

The Ninth Circuit issued two opinions addressing the issue of whether the Commission's jurisdiction over wholesale electric rates preempts petitioners' state law claims.<sup>135</sup> In *Grays Harbor*, Appellant brought contract-related claims against energy wholesalers alleging Appellees forced it to pay exorbitant electricity prices during the California crisis. In *California*, the Appellant alleged that the Appellee energy wholesalers violated California state antitrust laws. In both instances, the court concluded that because the FPA gives the FERC exclusive jurisdiction over interstate wholesale power rates, the state claims were preempted. In addition, the court in both cases reached the same conclusion under the filed rate doctrine.<sup>136</sup> In *Grays Harbor*, a divided panel granted petitioner leave to amend its case, stating, "[a] complaint that merely seeks declaratory relief as to contract formation issues would not necessarily intrude upon the rate-setting jurisdiction of FERC."<sup>137</sup> The panel majority posited that the district court could reach the conclusion that, because of the wide spread energy market crisis, "the contract was formed under circumstances of unilateral or mutual mistake." The district court under those circumstances would be able to find that no contract existed between the parties without interfering with the FERC's ratemaking authority.

## 3. Federal Removal Jurisdiction

The *California* court also determined whether the federal district court had removal jurisdiction over state court actions alleging a fraudulent failure to deliver reserve energy that might have averted the California energy crisis.<sup>138</sup> California alleged that the court lacked removal jurisdiction because the claim was based on a private contract, and not a federal statute, and also because removal would be contrary to the Eleventh Amendment's sovereign immunity for the state. The court rejected both arguments, holding that "California's state claim represented a naked attempt to enforce these federal obligations," and that a state cannot voluntarily bring a suit into state court and then invoke the Eleventh Amendment.<sup>139</sup>

The court then affirmed the district court in its opinion dated June 7, 2004. On July 27, 2004, California filed a petition for panel rehearing and rehearing en banc. The court denied this petition on October 29, 2004.

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134. See *Lockyer*, 383 F.3d at 1006.

135. Pub. Util. Dist. No. 1 of Grays Harbor County v. Idacorp Inc., 379 F.3d 641 (9th Cir. 2004); *California ex rel. Lockyer v. Dynegy, Inc.*, 375 F.3d 831 (9th Cir. 2004).

136. See *Entergy La., Inc. v. La. Pub. Serv. Comm'n*, 539 U.S. 39, 47 (2003) (noting that the Filed Rate Doctrine applies to the states only through federal preemption).

137. *Grays Harbor*, 379 F.3d at 652.

138. *Lockyer*, 375 F.3d at 834.

139. *Id.* at 843, 848.

## V. MARKET-BASED RATES

*A. Market Power Tests for Market-Based Rate Authority*

On April 14, 2004, and July 8, 2004, the Commission issued its initial order (Initial Order)<sup>140</sup> and rehearing order (Rehearing Order),<sup>141</sup> respectively, in cases involving the market-based rate authority of several major integrated systems. These orders establish how the Commission intends to replace its 2001-vintage market power test – known as the Supply Margin Assessment (SMA) – with a set of “indicative screens” and back-up analytical processes. The Commission relies on such indicative screens as a “first cut” in determining whether an applicant to sell wholesale power at market-based rates<sup>142</sup> (seeking either initial FERC authority or reauthorization under the triennial review requirement) would be sufficiently constrained by competitive market forces from imposing supra-market prices. If screen failure raises this concern, the applicant will be subject to further testing and/or market power mitigation.

The SMA test, first enunciated in *AEP Power Marketing, Inc.*,<sup>143</sup> revolves around a “pivotal supplier” concept. The concept adopts as its central premise that if peak demand in a given area cannot be met *without* an applicant’s generation capacity, then the applicant’s ability to withhold it – and thus unilaterally force up market prices – suggests it should not receive market-based rate authority, absent mitigation. But the SMA test, when unveiled in the *AEP Marketing* case, received such a battering from industry participants seeking rehearing that the Commission never finalized it. Instead, its 2004 Initial and Rehearing Orders inaugurated a new, multi-phased approach – one that, while retaining a modified version of the “pivotal supplier” screen, employs other indicative and in-depth screens, plus a raft of flexibility procedures designed to give parties (including intervenors) an opportunity to adapt the basic analytical tools to the particular circumstances.

The revised approach unveiled in the April 14 order begins with two forms of indicative screens. An applicant that fails either must undergo more intensive analyses to determine if it wields market power *or* proceed directly to the mitigation stage, as discussed further below. The initial screens are refined versions of tests the FERC has used in the past. The revamped pivotal supplier test – descended from the SMA – turns on whether the applicant’s available capacity is needed to meet the peak load in the relevant geographical unit—typically the “home” control area of the applicant. The other is a market share test; if that analysis reveals that the supplier’s uncommitted capacity is at least twenty percent of available capacity at the time of *lowest* demand in any of the four seasons of the year, then the applicant likewise fails and must choose between undergoing a more probing market power analysis or working out a

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140. *AEP Mktg., Inc.*, 107 F.E.R.C. ¶ 61,018 (2004).

141. *AEP Mktg., Inc.*, 108 F.E.R.C. ¶ 61,026 (2004).

142. An applicant requests initial market-based rate authority by filing a blanket rate schedule with the Commission to sell at negotiated rates pursuant to section 35.13 of the Commission’s regulations. Filing of Changes in Rate Schedule, 18 C.F.R. § 35.13 (2004).

143. *AEP Power Mktg., Inc.*, 97 F.E.R.C. ¶ 61,219 (2001).

mitigation solution with the FERC.<sup>144</sup> Both indicative screens incorporate a “simultaneous transmission import capability” study feature. The SMA screen tended, by assuming that available capacity could be accessed up to the Total Transmission Capacity (TTC), to overstate the amount of competitive capacity available from neighboring control areas to constrain the applicant. The simultaneous transmission import capability study provides a more realistic engineering look, compared to TTC, at how much competing capacity from neighboring control areas would actually be available under peak load conditions.<sup>145</sup>

The Commission acknowledged that the indicative tests – especially the second test that samples the applicant’s percentage of total uncommitted generation capacity at times of *lowest* demand – are designed to be conservative. On the other hand, the Commission liberalized the tests (versus SMA) by allowing deductions from the applicant’s total capacity to reflect native load and reliability obligations. As noted above, failure of one of the indicative screens leads to even more in-depth analysis—unless the applicant concludes it is so unlikely to pass a second wave of tests that it should proceed directly to the mitigation stage. The second stage of analysis includes re-running the pivotal supplier and market share screens with the overlay of a “delivered price test.” In brief, the “delivered price” versions would take into account the generation economics of the applicant’s and competing resources (e.g., input costs, historic market prices) to develop a truer picture of the probable competitive constraints on potential market power. In addition, a third analysis – *market concentration* (using the Hirschman-Herfindahl Index characteristically applied to merger proposals) – would be employed to help the Commission ascertain the competitive dynamics of the relevant market. The FERC emphasized in the Rehearing Order that it would not mechanically apply any single test (and would not necessarily withhold market-based rate authority due to failure of a single test), but rather would assess the results of all three analytic tools in arriving at a conclusion.

For the mitigation process (assuming the applicant cannot pass the indicative or back-up tests), the Commission’s “default” remedy is limiting the applicant to cost-based rates in its wholesale transactions.<sup>146</sup> However, the policy permits an applicant to take the initiative and propose an alternative mitigation measure. The Commission has indicated that it regards the product of the Initial and Rehearing Orders as “interim,” just as it had labeled the SMA analysis. The Commission stated that it would commence a new investigation to consider how to determine and restrict market power in the growing number of situations where this issue arises.

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144. This screen can be seen as the lineal descendant of the old hub and spoke market share procedure for determining market dominance in generation that the FERC employed prior to adopting the SMA test in 2001.

145. Simultaneous transmission import capability is also used in assessing market share under the second test.

146. Short-term sales (up to one week) would be subject to a ceiling of incremental cost plus a margin of ten percent; longer-term sales would be priced under embedded cost rates, with contracts filed at the Commission—in other words, a return to traditional cost-based regulation.

Using the interim market power screens, on December 15, 2004, the Commission acted on sixteen pending market-based rate filings in various dockets, permitting market-based rates to stay in place without further proceedings in about half of the cases. For those that failed the Commission's new interim market power initial screen, future power sales at market rates will be subject to potential refund obligation. The Commission ordered further proceedings under the FPA section 206 to provide refund protections to wholesale customers while allowing these companies another opportunity to demonstrate that they do not have market power and to explore alternative means of mitigating any market power.<sup>147</sup>

*B. Rulemaking in Docket No. RM04-7-000*

On April 14, 2004, the Commission issued an order inquiring whether it should initiate a rulemaking proceeding with respect to its current four-pronged analysis for determining whether to grant market-based rates (April 14 Order).<sup>148</sup> The four prongs are: (1) whether the applicant has generation market power; (2) whether the applicant has transmission market power; (3) whether the applicant can erect barriers to entry; and (4) whether there are concerns involving the applicant that relate to affiliate abuse and/or reciprocal dealing.<sup>149</sup>

The April 14 Order based a possible rulemaking on dual grounds: (1) there have been many changes in the industry since the four-pronged test was promulgated, requiring re-examination of the test to support market-based rates; and (2) there are no codified regulations for obtaining authorization to charge market-based rates.<sup>150</sup> The inquiry will address, but not be limited to: (1) whether the Commission should retain or modify its existing four-prong test; (2) whether the factors the Commission considers under the existing test should be revised (e.g., whether the analysis should explicitly address vertical market power issues); (3) whether the interim generation market power screens that were adopted in the AEP Order (AEP Order)<sup>151</sup> should be retained over the long-term; (4) whether the Commission should adopt different approaches to affiliate transactions; and (5) whether the Commission should promulgate regulations for market-based rate filings.<sup>152</sup>

The Commission held a technical conference on June 9, 2004, to frame the issues in this proceeding. After receiving comments, the FERC held a second technical conference on December 7, 2004.<sup>153</sup> This technical conference addressed issues associated with transmission market power (e.g., whether the

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147. See Press Release, FED. ENERGY REG. COMM'N, COMMISSION ACTS ON MARKET-BASED RATE FILINGS, ADVANCES NEW MARKET OVERSIGHT POLICY (Dec. 15, 2004), available at <http://www.ferc.gov/press-room/pr-current/12-15-04-mbr.pdf>.

148. *Market-Based Rates for Public Utilities*, 107 F.E.R.C. ¶ 61,019 (2004).

149. *Id.*

150. 107 F.E.R.C. ¶ 61,019.

151. *AEP Power Mktg., Inc.*, 107 F.E.R.C. ¶ 61,018 (2004); *order on reh'g*, 108 F.E.R.C. ¶ 61,026 (2004). The two interim generation market screens are the market share analysis applied on a seasonal basis and the pivotal supplier analysis based on a control area's annual peak demand. *Id.* at 61,054-55.

152. *Market-Based Rates for Pub. Utils.*, 107 F.E.R.C. ¶ 61,019 (2004).

153. Notice of Technical Conference, *Market Based Rates for Public Utilities*, 69 Fed. Reg. 67,573 (2004). The Commission has also solicited comments on the December 7 technical conference.

Commission's pro forma open access transmission tariff adequately mitigates transmission market power and other proposals to identify and mitigate transmission market power) and barriers to market entry.

On December 22, 2004, the Commission issued a notice stating that another technical conference would be held on January 27–28, 2005, to discuss issues associated with generation market power (e.g., including whether to modify the interim generation market power screens adopted by the Commission in the *AEP Order* and the appropriate mitigation for those found to have generation market power) and issues of affiliate abuse and reciprocal dealing, including any mitigation measures the Commission should consider.<sup>154</sup>

As of February 1, 2005, the Commission had not issued a Notice of Proposed Rulemaking in Docket No. RM04-7-000.

#### VI. STANDARDIZATION OF LARGE GENERATOR INTERCONNECTION PROCEDURES AND AGREEMENTS

On July 24, 2003, following a lengthy public rulemaking, the Commission issued its final rule that standardized the procedures and agreements through which generators must obtain interconnections with transmission facilities.<sup>155</sup> The products of Order No. 2003 – the “pro forma” Large Generation Interconnection Procedures and Large Generator Interconnection Agreement (LGIP and LGIA, respectively) – were designed to overhaul an interconnection process “fraught with delays and lack of standardization that discourage merchant generators . . . .”<sup>156</sup> Conversely, Standardization, through the pro forma LGIP and LGIA of the most balanced, transparent rules and best practices in the industry, conversely, was intended to help achieve the non-discrimination and comparability goals the Commission has pursued on many fronts of its transmission policy. The numerous rehearing and clarification petitions spawned by Order No. 2003 resulted, in the course of 2004, in two major rehearing orders.<sup>157</sup> Some of the more significant modifications to the LGIP and LGIA resulting from Orders No. 2003-A and 2003-B are discussed below.<sup>158</sup>

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154. Notice of Technical Conference, *Market Based Rates for Public Utilities*, 69 Fed. Reg. 78,408 (2004).

155. Order No. 2003, *Standardization of Generator Interconnection Agreements and Procedures*, F.E.R.C. STATS. & REGS. ¶ 31,146, 68 Fed. Reg. 49,846 (2003) (codified at 18 C.F.R. § 35.28(f)) [hereinafter Order No. 2003].

156. Order No. 2003-A, *Standardization of Generator Interconnection Agreements and Procedures, order on reh'g*, 69 Fed. Reg. 15,932 (2004), F.E.R.C. STATS. & REGS. ¶ 31,160 [hereinafter Order No. 2003-A].

157. Order No. 2003-A, was issued on March 5, 2004. *Id.* The second rehearing order, Order No. 2003-B, *Standardization of Generator Interconnection Agreements and Procedures, order on reh'g and directing compliance*, 70 Fed. Reg. 265 (2005), F.E.R.C. STATS. & REGS. ¶ 31,171 [hereinafter Order 2003-B], was issued on December 20, 2004.

158. For simplicity, except when the context specifically concerns one of the three outstanding orders constituting the final rule, we will refer to the entirety as “Order No. 2003.”

### A. Scope and Jurisdiction

Nominally, Order No. 2003 applies only to *jurisdictional* transmission facilities. But, by virtue of the same reciprocity principle that makes Order No. 888-based OATTs applicable as a practical matter to many non-jurisdictional transmission facility owners as well, the Commission anticipated that Order No. 2003 would be adhered to voluntarily in the non-jurisdictional community.<sup>159</sup> To address situations where a generator proposes to be interconnected to a distribution system that would not generally be regulated under the FPA, the Commission has designated facilities with a primary distribution function but which also are used by interconnecting generators to facilitate wholesale power transactions as dual use facilities. In Order No. 2003-A, the Commission reaffirmed its jurisdiction over such dual use facilities for purposes of applying the LGIP and LGIA, so long as: (1) the facilities are subject to an OATT at the time an interconnection request is submitted; and (2) the generator seeks the opportunity to make wholesale sales.<sup>160</sup> The Commission revisited this issue in Order 2003-B. Responding to Southern California Edison's objection that the Commission erroneously stated that a *state agency* would retain jurisdiction over an interconnection to dual use facilities when the facility in question "is not subject to a Commission-approved OATT," the Commission granted rehearing, retracted its prior statement, and affirmed that it *would* have jurisdiction under such circumstances because, if the facility were "dual use," it would necessarily be "subject to an OATT."<sup>161</sup>

### B. Transmission Credits to Reimburse Generators for Network Upgrades

One of the most controversial aspects of Commission policy on generator interconnections prior to Order No. 2003 was its allocation of the costs for improvements to the transmission grid necessary to interconnect and safely receive the output of the generator. Under the FERC's pricing policy in the prior cases – which it generally carried over into Order No. 2003 – the allocation of costs for completing an interconnection fell into two distinct categories. Facilities necessary to interconnect the grid to the interconnection customer at its site (called "Interconnection Facilities" under Order No. 2003) are directly assigned to the generator. Facilities needed to upgrade the grid to accommodate the interconnection and anticipated deliveries of electricity from the generator (called "Network Upgrades") are initially paid for by the generator but eventually reimbursed through credits applied to transmission charges. Many Transmission Providers (and some state commissions) in the proceeding that resulted in Order No. 2003 (and on rehearing) argued that the Commission should abandon this bifurcated pricing policy and authorize Transmission

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159. See Order No. 2003, *supra* note 155, at 30,551.

160. Order No. 2003-A, *supra* note 156, at 30,968.

161. Order No. 2003-B, *supra* note 157, at 31,283. This narrow clarification by the Commission does not, however, entirely resolve the broader issue raised by Southern California Edison, which had suggested that the Commission's jurisdiction over interconnections to effect wholesale sales – and hence, the application of Order No. 2003 – should not be stymied because, at the time of the interconnection, there happens to be no pre-existing generator interconnection or "dual use" (i.e., the distribution facility is used only for bundled retail transactions and the facilities have not been "subject to an OATT").



Providers to directly assign the full spectrum of interconnection facility costs (including Network Upgrades) to interconnecting generators. However, the Commission did not incorporate such a direct assignment policy into Order No. 2003, with one important exception for independent Transmission Providers (e.g., RTOs and ISOs). Independent Transmission Providers are free to propose pricing alternatives (often referred to as participant funding) that place a greater ultimate financial responsibility for Network Upgrades on generators.<sup>162</sup>

Additional issues regarding the scope and mechanics of transmission crediting as a means of generator reimbursement were taken up in the two rehearing orders. Order 2003-A reversed the policy announced in Order 2003 that generators should receive credits on transmission services from a particular Transmission Provider even if the source of power was another unit (not the project for which the Network Upgrades being reimbursed were constructed). Faced with arguments that this could result in system transmission customers – who pay for the credits as the upgrade assets are “rolled in” to the rate base – subsidizing upgrades that proved unnecessary (e.g., because the generator stopped delivering into the transmission system), the Commission limited transmission credits to services involving the unit that drove the upgrades.<sup>163</sup> The Commission also rescinded its rule in Order 2003 that required full generator reimbursement at the end of five years (i.e., through a lump-sum payment)—regardless of whether cumulative transmission charges applicable to the generator had by then equaled the upfront cost of the upgrades plus interest.<sup>164</sup> However, when this new approach to generator reimbursement drew protests from generators on rehearing of Order 2003-A, the FERC again refined the rule in Order 2003-B by placing a cap of twenty years on the period a Transmission Provider has to complete network upgrade reimbursements.<sup>165</sup> In addition, the Commission reaffirmed in Order 2003-A that generator payments required to reinforce a *distribution system* to which it was interconnecting would *not* be subject to reimbursement through crediting of transmission service payments (i.e., these network upgrades could be directly assigned to the interconnection customer).<sup>166</sup>

### C. Pricing Options for Transmission Service

While the Commission continued to maintain, as it did pre-Order No. 2003, that the integrated grid is a single piece of equipment and that network upgrades benefit all customers,<sup>167</sup> Order No. 2003-A provided that transmission providers retained an option to charge interconnection customers for transmission services on the basis of *incremental costs* imposed by the generator to accommodate the

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162. Order No. 2003-A, *supra* note 156, at 31,065–70.

163. The Commission made a similar ruling with regard to Network Upgrades a generator must pay for on an adjacent (Affected) system (i.e., not the system to which it directly interconnects). A refund obligation would only attach to the extent that the unit requiring the upgrade took actual transmission service on such an Affected System.

164. Order No. 2003-A, *supra* note 156, at 30,969.

165. Order No. 2003-B, *supra* note 157, at 31,288.

166. Order 2003-A, *supra* note 156, at 30,969.

167. *Id.* at 31,048.

interconnection (in lieu of an embedded system average transmission charge). Charging the customer both the rolled-in average cost (including the cost of the upgrades) *plus* a direct assignment of the specific costs of accommodating the interconnection – which the Commission refers to as “and pricing” – was forbidden.<sup>168</sup> So long as a transmission provider avoids “and pricing,” it may charge the *higher of* incremental or embedded charges for transmission services.<sup>169</sup> This, the Commission stated, would avoid subsidies from general system customers to the generator. In Order No. 2003-B, the Commission clarified that an interconnection customer subjected to *incremental* transmission charges under the “higher of” policy would be entitled to transmission credits up to the full level of those incremental charges.<sup>170</sup>

#### D. Compliance Filings and Flexibilities

Order No. 2003 envisioned prospective filings, in early 2004, by all subject transmission providers, to amend their OATTs in order to incorporate the LGIP and LGIA. The pro forma versions of these documents included as an appendix to Order No. 2003 would be the template for these individual tariff filings. Variations to the template would be considered by the Commission—but under two different sets of criteria. Independent transmission providers (such as RTOs and ISOs), because they do not raise comparability concerns, would be free to propose changes under a liberal regional variation standard. Variation proposals by non-independent or affiliated Transmission Providers, would be judged under the equal or superior standard, which the Commission has used to weigh departures requested by Transmission Providers from Order No. 888’s pro forma tariff.<sup>171</sup> As a practical matter, this meant that deviations from the LGIP or LGIA sought by non-independent transmission providers could pass muster only by demonstrating that existing regional reliability practices mandated the changes. The Commission applied this approach in response to a series of company filings in 2004.<sup>172</sup>

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168. Order No. 2003-A, *supra* note 156, at 31,046.

169. *Id.* at 31,048. The Commission explained that in most cases, the aggregate transmission charges paid by a generator exceed the cost of network upgrades, so ratepayers receive a net benefit from the transmission provider charging the embedded system rate for transmission, even reduced by transmission credits. Where this is not the case, the transmission provider can protect system customers by assessing a “higher of” incremental rate.

170. Order 2003-B, *supra* note 157, at 31,289. The Commission also rejected suggestions that the “higher of” policy, with the option to charge incremental rates, would not necessarily protect native load customers thus, concerned parties must make specific showings in individual cases where this might be the case, rather than relying on “hypotheticals” in the context of a generic rulemaking.

171. Order No. 2003, *supra* note 155, at 30,549.

172. Compare, e.g., *S. Co. Servs., Inc.*, 109 F.E.R.C. ¶ 61,070 (2004) with *Midwest Indep. Transmission Sys. Operator, Inc.*, 109 F.E.R.C. ¶ 61,085 (2004).

## VII. RELIABILITY

A. *Activities at the FERC*

On April 19, 2004, the FERC issued a Policy Statement on reliability (Policy Statement).<sup>173</sup> The purpose of the Policy Statement was to formally respond to the recommendations contained in the U.S.-Canada Power System Outage Task Force's Interim and Final Blackout Reports on initiatives the FERC should undertake. In the Policy Statement, the FERC:

- Criticized existing reliability standards and called for the North American Electric Reliability Council (NERC) to develop revised reliability standards that were “clear, unambiguous, measurable and enforceable.”<sup>174</sup>
- Clarified that the term “Good Utility Practice,” which is used in open access transmission tariffs and service agreements, will be interpreted “to include compliance with NERC reliability standards or more stringent regional reliability council standards.”<sup>175</sup>
- Reiterated an earlier statement of policy that the FERC will approve applications to recover prudently incurred costs necessary to safeguard the reliability and security of the system in light of the terrorist attacks of September 11, 2001,<sup>176</sup> and extended that policy to include the recovery of prudent reliability expenditures “including those for vegetation management, improved grid management and monitoring equipment, operator training and compliance with NERC standards.”<sup>177</sup>
- Made a general commitment to work closely with Canada and Mexico on reliability issues in the future, including the success of any Electricity Reliability Organization (ERO) that might be established.<sup>178</sup>
- Established a staff task force to investigate alternative, independent funding mechanisms for the NERC.<sup>179</sup>

On April 19, 2004, the FERC also issued an order requiring entities that own, control, or operate certain designated transmission facilities within the continental United States to respond to a survey concerning their vegetation management practices.<sup>180</sup> Using its broad authority under section 311 of the

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173. Policy Statement, *Policy Statement on Matters Related to Bulk Power System Reliability*, 69 Fed. Reg. 22,502 (2004).

174. *Id.* at 22,504.

175. 107 F.E.R.C. ¶ 61,052, at 61,168.

176. Policy Statement, *Extraordinary Expenditures Necessary to Safeguard Nat'l Energy Supplies*, 96 F.E.R.C. ¶ 61,299, 61,129 (2001).

177. 107 F.E.R.C. ¶ 61,052, at 61,169.

178. *Id.* at 61,170.

179. 107 F.E.R.C. ¶ 61,052, at 61,171.

180. *Reporting By Transmission Providers on Vegetation Management Practices Related to Designated Facilities*, 107 F.E.R.C. ¶ 61,053 (2004).

FPA<sup>181</sup> to conduct investigations in order to obtain information necessary or appropriate as a basis for recommending legislation, this survey was directed not only to jurisdictional public utilities, but also to entities otherwise outside of the Commission's jurisdiction. The results of this survey formed the foundation for the report that the FERC submitted to the President and Congress on September 7, 2004.<sup>182</sup>

The FERC's Vegetation Management Report contained ten specific recommendations. The first was that, "Congress should enact legislation to make reliability standards mandatory and enforceable under federal oversight,"<sup>183</sup> and the second was that, "[e]ffective transmission vegetation management requires clear, unambiguous, enforceable standards that adequately describe the actions necessary by each responsible party."<sup>184</sup>

Throughout 2004, the FERC prepared for the anticipated, eventual enactment of the consensus federal electric reliability legislation that would provide for the establishment of an ERO and the promulgation of mandatory reliability standards. The FERC is an active participant in the Bilateral ERO Working Group, which includes governmental organizations both within the United States and in Canada. The purpose of this working group is to arrive at a common understanding among the membership on certain basic questions concerning the form and governance of the ERO before Congress enacts consensus reliability legislation. The assumption of the Bilateral ERO Working Group is that the FERC will be on a very tight schedule to promulgate implementation of regulations pertaining to the operations of the ERO within the United States once reliability legislation is enacted. Among the issues being considered by the Bilateral ERO Working Group are the questions of ERO governance, funding, relationships to governmental entities in the United States and Canada particularly with respect to standards development, enforcement activities, and the role of regional reliability entities once the ERO is established.

Calendar year 2004 ended with the FERC issuing an order requiring control area operators and transmission providers to respond to a 205-question survey on operator training practices.<sup>185</sup> In its order establishing the survey process, the FERC noted that in its final report on the August 14, 2003 blackout the U.S.-Canada Power System Outage Task Force found that operator performance was one of the root causes of the blackout. Using the same broad authority it used to undertake the earlier vegetation management survey, the operator training survey was directed both to jurisdictional public utilities and to entities otherwise outside of the Commission's jurisdiction. The goal of the survey was to determine the breadth of training practices across the industry, identify best practices, and evaluate minimum requirements for an effective training program. Responses to the survey were due on January 31, 2005.

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181. 16 U.S.C. § 825j (2000).

182. FED. ENERGY REG. COMM'N, UTILITY VEGETATION MANAGEMENT AND BULK ELECTRIC RELIABILITY REPORT (2004) [hereinafter VEGETATION MANAGEMENT REPORT].

183. *Id.*

184. VEGETATION MANAGEMENT REPORT, *supra* note 182, at 3.

185. *Survey on Operating Training Practices*, 105 F.E.R.C. ¶ 61,365 (2004).

### B. Activities at the NERC

On February 10, 2004, the Board of Directors of the NERC established its Readiness Audit Program. The program was established in response to the August 14, 2003, blackout and is intended to audit the reliability readiness of all reliability coordinators and control areas with immediate attention given to addressing the deficiencies identified in the August 14<sup>th</sup> blackout investigation.

The NERC was underway with its audits by March 2004. By the end of 2004, more than sixty audits had been completed, with twenty-seven final audit reports posted at the NERC website. The readiness audits will be conducted on a three-year cycle.

On June 15, 2004, the Board of Directors of the NERC approved a written plan for accelerating the adoption of NERC reliability standards.<sup>186</sup> The purpose of the plan was to accelerate the process that the NERC Board began in June, 2002 with the approval of a new, consensus-based standards development procedure founded on principles established by the American National Standards Institute. Although the NERC cited several reasons for why this process should be accelerated, all of the reasons related to the August 14, 2003, blackout and the need to establish standards that are unambiguous and measurable at the earliest possible date. At the end of 2004, the NERC had made significant progress in developing new standards with “Version 0 Reliability Standards” having been approved in a vote of stakeholders.

The Western Electricity Coordinating Council (WECC), lodging a formal objection to the assessment it received from the NERC for 2005, sought a substantial reduction in those dues.<sup>187</sup> The WECC not only complained that its dues had increased significantly when compared to the dues it paid for 2004, but it also complained that several of NERC’s programs – particularly its standards development process and readiness audits process – were driven by blackouts in the eastern United States that could not spread to the WECC, and were duplicative of processes the WECC already had in place.

## VIII. AFFILIATE TRANSACTIONS CASES

In a series of orders explained below, the Commission has offered new guidance on how it will scrutinize transactions between a public utility and its affiliates in order to ensure that franchise utilities engaging in such transactions do not unduly favor its affiliates. The orders set a common standard of review – first enunciated in *Boston Edison Co. re: Edgar Electric Energy Co. (Edgar)*<sup>188</sup> – for affiliate transactions. The FERC explained its policy by stating that its view

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186. N. AM. ELEC. RELIABILITY COUNCIL, PLAN FOR ACCELERATING THE ADOPTION OF NERC RELIABILITY STANDARDS (2004), available at [http://www.nerc.com/pub/sys/all\\_updl/standards/Accelerated\\_Standards\\_Transition\\_Plan\\_Approved\\_by\\_Board\\_06\\_04.pdf](http://www.nerc.com/pub/sys/all_updl/standards/Accelerated_Standards_Transition_Plan_Approved_by_Board_06_04.pdf).

187. *WECC Protests 2005 NERC Dues; Says West Already Does Much of New East-driven Activity*, Jan. 3, 2005, at 22.

188. *Boston Edison Co. re: Edgar Electric Energy Co.*, 55 F.E.R.C. ¶ 61,382 (1991).

of what is consistent with the public interest must necessarily evolve over time to adjust for changes in the market (*Ameren*).<sup>189</sup>

#### A. *The Edgar Standard*

The *Edgar* standard was developed to facilitate review of market-based power purchase agreements between affiliates; the essence of the test is that a franchised utility must make a showing that a sale of power at market-based rates from its own affiliate is reasonably priced compared to alternatives in the market.<sup>190</sup> Toward that end, *Edgar* laid out three methods by which a utility could demonstrate that a particular transaction is presumptively reasonable. First, the utility could offer evidence of direct competition between the affiliate and unaffiliated suppliers in a formal solicitation or informal negotiation process.<sup>191</sup> Second, the utility could offer evidence of the prices that non-affiliated buyers would pay for similar services from the affiliate.<sup>192</sup> Finally, the utility could introduce benchmark evidence showing the prices, terms, and conditions of sales made by non-affiliated sellers.<sup>193</sup>

##### 1. Extension of Edgar Test to Cost-of-Service, as Well as Market-Based, Sales

In *Southern California Edison Co. ex rel. Mountainview Power Co., (Mountainview)*,<sup>194</sup> the Commission expressed concern that affiliate preference, in both the market-based or cost-based sales context, could harm competition.<sup>195</sup> To counter the potential for affiliate preferences, the Commission announced that the *Edgar* test would apply to all power purchase agreements between affiliates, thus it was no longer restricted only to market-based sales.<sup>196</sup>

##### 2. Application of Edgar Test to FPA Section 203 Proceedings

The Commission also applied the *Edgar* test pursuant to section 203 of the FPA, to a proposed sale of two generating plants from Ameren Energy Generating Company (AEG) to an affiliated franchise utility, Union Electric Company d/b/a AmerenUE (AmerenUE).<sup>197</sup> In the order setting the matter for hearing in *Ameren*, the FERC asserted that it needed to augment its section 203 analysis where affiliate transactions are involved.<sup>198</sup> The Commission expressed concern that a franchise utility could provide its unregulated affiliates with a

189. *Ameren Energy Generating Co.*, 108 F.E.R.C. ¶ 61,081, 61,411 (2004).

190. 55 F.E.R.C. ¶ 61,382, at 62,169.

191. *Id.* at 62,168.

192. 55 F.E.R.C. ¶ 61,382, at 62,168–69.

193. *Id.* at 62,169.

194. *S. Cal. Edison Co. ex rel. Mountainview Power Co.*, 106 F.E.R.C. ¶ 61,183 (2004).

195. *See id.* at 61,645. (“We are also concerned that granting undue preference to affiliates, whether through cost-based or market-based transactions, could cause long-term harm to the wholesale competitive market.”).

196. 106 F.E.R.C. ¶ 61,183, at 61,645.

197. The transaction was FERC-jurisdictional because it involved the sale of certain transmission facilities associated with the subject generators.

198. *Ameren Energy Generating Co.*, 103 F.E.R.C. ¶ 61,128, 61,412–13 (2003).

“safety net” unavailable to independent entities, meaning that the franchise utility stands ready to assume its affiliated merchant’s generation in times of reduced market demand.<sup>199</sup> The FERC then instructed the presiding administrative law judge (ALJ) to apply a test similar to that used to evaluate intra-corporate sales contracts, as outlined in *Edgar*.<sup>200</sup>

After an initial decision,<sup>201</sup> the FERC found no affiliate abuse in AmerenUE’s request for proposal (RFP) process<sup>202</sup> so that the proposed transaction would be consistent with the public interest.<sup>203</sup> The Commission also announced that it would scrutinize for affiliate abuse in the section 203 context as well as the section 205 context.<sup>204</sup> According to the FERC, because the market for generating assets is not as liquid as the market for power purchase agreements, a competitive solicitation through a formal RFP is likely the most effective way to show that an affiliate transaction is not contaminated by affiliate abuse.<sup>205</sup> Although the order does not require the use of competitive solicitations where affiliate transactions may be involved, the FERC suggested that the use of such a process would increase the likelihood of timely FERC approval.<sup>206</sup> The FERC also identified the following four parameters for fair competitive solicitations: (1) use of a transparent process; (2) use of precisely defined products; (3) standardization of evaluation criteria and their equal application to all bidders; and (4) an independent oversight process.<sup>207</sup>

### 3. Extension of the Means to Meet the Edgar Test Articulated in the Section 203 Context to the Section 205 Context

The same day the FERC issued its order in *Ameren*, it clarified that the four factors identified in *Ameren* as indicative of a fair solicitation process (i.e.,

199. *Id.* at 61,412.

200. 103 F.E.R.C. ¶ 61,128, at 61,143 (stating the Commission’s view that *Edgar* should apply in the context of a section 203 proceeding).

201. *Ameren Energy Generating Co.*, 106 F.E.R.C. ¶ 63,011 (2004).

202. 108 F.E.R.C. ¶ 61,081, at 61,407.

203. *Id.* at 61,405.

204. *Ameren Energy Generating Co.*, 108 F.E.R.C. ¶ 61,081, at 61,410.

205. *Id.* at 61,411.

206. 108 F.E.R.C. ¶ 61,081, at 61,411.

207. *Id.* at 61,411–12. In partial dissent, Commissioner Kelliher expressed misgivings with his colleagues’ findings in a number of respects. First, the Commissioner would not apply the *Edgar* test as explicated in *Ameren* in section 203 proceedings because the standard under section 203 – protecting the public interest – is not the same as the standard in a section 205 proceeding – assuring just and reasonable/non-discriminatory rates. See *Ameren Energy Generating Co.*, 108 F.E.R.C. ¶ 61,081, 61,414 (2004) (Kelliher, C., dissenting in part) (“In my view, the Commission’s interest in proceedings under Section 203 is fundamentally different from its interest under Section 205 . . . because the legal standard is different.”). Commissioner Kelliher also questioned whether FERC has the authority to apply this new policy to asset transfers such as the one in question here, arguing instead that the states should regulate these types of issues. See *id.* (“[I]t is the responsibility of a state commission, not this Commission, to ensure that a state-regulated utility does not subsidize an affiliate in the purchase of an asset.”). Finally, he noted that he is dubious of the “safety net” theory with which the majority seemed so concerned. 108 F.E.R.C. ¶ 61,081, at 61,414.

Our competitive solicitations policy appears designed to guard against competitive impacts based on a theory that is speculative at best. I disagree with the competitive solicitations policy because I believe it is designed to solve a problem that does not exist, and does not advance the Commission’s ability to assess legitimate market power issues.

transparency, clear and non-discriminatory product definition, stated evaluation criteria, and third-party administration) also would apply in the section 205 context.<sup>208</sup>

### B. AEP/CSW Merger Remand

After two years of inaction, the Securities & Exchange Commission (SEC) in August 2004 acted in response to the U.S. Court of Appeals for the District of Columbia Circuit's 2002 remand<sup>209</sup> of the SEC's approval of AEP's merger with CSW.<sup>210</sup> AEP and CSW planned to interconnect their systems, which were separated by hundreds of miles at their nearest points, through a 250 MW, unidirectional transmission service contract with Ameren Corporation (the "contract path").<sup>211</sup>

Under the Public Utility Holding Company Act of 1935 (PUHCA), the SEC must review "all transactions in which a registered holding company proposes to acquire securities or utility assets of another holding or public-utility company."<sup>212</sup> The PUHCA provides two exceptions to the SEC's approval authority in these cases.

The first exception involves cases where the post-acquisition entity no longer qualifies as a "single integrated public-utility system."<sup>213</sup> The SEC has interpreted this exception as a four-part test: (a) the "interconnection requirement" requires that the resulting entity's assets be "physically interconnected or capable of physical interconnection;" (b) the "coordination requirement" requires that the entity be able to operate its assets "as a single interconnected and coordinated system;" (c) the "region requirement" specifies that the system "be confined to a 'single area or region;'" (d) and the "localization requirement" mandates that the system "not be so large as to impair . . . the advantages of localized management, efficient operation, and the effectiveness of regulation."<sup>214</sup>

The second exception applies where the proposed transaction does not "serve the public interest by tending towards the economical and efficient development of an integrated public-utility system" (the "Efficiencies and Economies" exception).<sup>215</sup>

In a June 2000 order, the SEC found that neither exception applied to the proposed AEP-CSW merger and approved the transaction. Two electric utility associations – the American Public Power Association and the National Rural

208. *Allegheny Energy Supply Co.*, 108 F.E.R.C. ¶ 61,082, 61,417 (2004).

209. *Nat'l Rural Elec. Coop. Ass'n v. SEC*, 276 F.3d 609 (D.C. Cir. 2002).

210. The proposed transaction would merge CSW's wholly-owned subsidiaries, supplying power to parts of Arkansas, Louisiana, Oklahoma, and Texas, with AEP's wholly-owned generating company and electric utilities, supplying power to parts of Indiana, Kentucky, Michigan, Ohio, Tennessee, Virginia, and West Virginia. The agreement designated the post-acquisition company as "New AEP."

211. *Nat'l Rural Elec. Coop.*, 276 F.3d at 612.

212. 15 U.S.C. § 79j (2000).

213. 15 U.S.C. § 79j(e)(1); 15 U.S.C. § 79k(b)(1) (2000).

214. *Nat'l Rural Elec. Coop.*, 276 F.3d at 61 (citing *Elec. Energy, Inc.*, 38 S.E.C. 658, 668 (1958)).

215. 15 U.S.C. § 79j(c)(2) (2000); see also *Wis. Envtl. Decade, Inc. v. SEC*, 882 F.2d 527–528 (D.C. Cir. 1989).



Electric Cooperative Association (Petitioners) – appealed the approval to the D.C. Circuit.<sup>216</sup>

Petitioners first claimed that the SEC inappropriately applied the interconnection requirement. In response, the court expressed doubt that a unidirectional contract path could satisfy the PUHCA requirement that the system operate “‘as a single interconnected and coordinated’ whole.”<sup>217</sup> The court also found that the SEC had departed from its own precedent in relying on this contract path to approve the merger.<sup>218</sup> In several prior orders, the SEC had stated that “contract rights cannot be relied upon to integrate two *distant* utilities.”<sup>219</sup> The court pointed out that when the SEC did rely solely on contract path to meet the interconnection requirement, the path ran in both directions between “relatively closely-situated utility assets,”<sup>220</sup> and found that the SEC had not justified this departure from “clear policy.”<sup>221</sup>

Petitioners next argued that the SEC erred in applying the region requirement. The court disagreed with the Petitioners that the SEC should have relied on some industry standard such as NERC reliability regions or FERC RTOs. In analyzing this criterion, the court found fault with the SEC’s analysis in two respects. First, while prior SEC orders addressing the region requirement had considered factors such as geography and demographics, this decision made no evidentiary findings on such criteria. In particular, the SEC failed to explain why the “noncontiguous and seemingly dissimilar regions” included in New AEP constituted one single area or region.<sup>222</sup> The court also faulted the SEC for “erroneously conclud[ing] that a proposed acquisition that satisfies PUHCA’s other requirements also meets the statute’s region requirement,”<sup>223</sup> and admonished the SEC that it cannot read the requirement so flexibly so as to read it out of PUHCA entirely.<sup>224</sup> Thus, in January 2002, this case was remanded to the SEC, where it languished for two and a half years.<sup>225</sup>

In August 2004, the SEC issued an order that finally addressed the remand by setting the case for hearing. The topics set for hearing, held January 10, 2005,

216. *Nat’l Rural Elec. Coop.*, 276 F.3d at 619. Though Petitioners claimed that the Efficiencies and Economies Exception applied as well, the court disagreed. While Petitioners argued that the SEC should not have accepted AEP and CSW’s projected cost savings estimate, the Court, relying on the “considerable deference” it owes to such determinations, and on Petitioners lack of contradictory evidence, found the SEC within its discretion to accept the estimate. *Id.*

217. *Nat’l Rural Elec. Coop.*, 276 F.3d at 615.

218. *Id.*

219. *Nat’l Rural Elec. Coop.*, 276 F.3d at 615.

220. *Id.* at 616.

221. *Nat’l Rural Elec. Coop. Ass’n v. SEC*, 276 F.3d 609, 615 (D.C. Cir. 2002).

222. *Id.* at 618.

223. *Nat’l Rural Elec. Coop.*, 276 F.3d at 618. The SEC had stated “In view of these considerations, [that the system’s size ‘will not impair efficient operation, localized management or effective regulation . . . and will result in economies and efficiencies’] we find that the New AEP System will operate in a single area or region.” *Id.* at 618.

224. *Nat’l Rural Elec. Coop.*, 276 F.3d at 618.

225. *In re Am. Elec. Power Co.*, SEC File No.3-11616, 2 (Nov. 30, 2004) [hereinafter NRECA/APPA Statement of Position]. As of October 6, 2004, NRECA and APPA were made parties to the proceeding. As Petitioners pointed out in their statement of position, the AEP-CSW merger remains unlawful under the PUHCA without the SEC approval order, and the merger is still pending.

included “whether AEP and CSW are interconnected, through a unidirectional contract path or otherwise, and whether the resulting combined system operates in a single area or region.”<sup>226</sup> Citing the need to bolster the record before it, the SEC requested information regarding “what specific facts about AEP’s and CSW’s electric systems and the geographic area covered by their systems are relevant to the required determinations.”<sup>227</sup> The SEC noted that it would allow parties to submit facts “regarding the current state of the utility industry, in particular facts regarding the growth of regional transmission organizations and the unbundling of generation, transmission and distribution assets that has occurred in recent years,” as well as “facts – demographic, economic, and otherwise – regarding the geographic area in which the combined AEP-CSW system operates . . . .”<sup>228</sup>

In its statement of position, AEP indicated that it will introduce evidence regarding: (1) the trade flows and infrastructure within the combined system’s region; (2) the combined system’s location primarily within the Eastern Interconnection; (3) the location of the combined system within the soon-to-be-formed alliance of three RTOs; and (4) the location of the combined utility within first-tier connections. The SEC Division of Investment Management staff generally agree with AEP that those topics are relevant to the SEC’s inquiry. Petitioners counter that the contention that CSW and AEP are in the same “region” is so far-fetched as to altogether ignore SEC’s “region” requirement.

#### IX. MIRANT BANKRUPTCY – JURISDICTIONAL DISPUTE

In December 2003, Fitch Ratings commented that big energy bankruptcies had dominated the preceding three years. The big energy bankruptcies involved Enron, Pacific Gas & Electric Co., NRG Energy, Inc., Mirant Corp. (Mirant),<sup>229</sup> and NorthWestern Corp. An important issue in utility bankruptcies is the extent to which the jurisdiction of federal and state regulatory agencies is preempted by bankruptcy law. The discussion below highlights developments involving the Mirant bankruptcy, in which the FERC and the courts have addressed the overlapping jurisdiction of regulatory agencies and bankruptcy courts.

Mirant filed for bankruptcy protection on July 14, 2003.<sup>230</sup> As of the date of this writing, Mirant has not filed a disclosure statement or plan of reorganization. Of greatest interest to those not directly involved in the case is the ongoing dispute among Mirant, Potomac Electric Power Company (PEPCO) and the FERC regarding the rejection of an executory contract.

On August 28, 2003, Mirant requested that the bankruptcy court issue an order authorizing it to reject an agreement with PEPCO and enjoining any person or entity from seeking specific performance of the rejected contract after the date of an order. The bankruptcy court issued an *ex parte* temporary restraining

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226. *Id.*

227. NRECA/APPA Statement of Position, *supra* note 213, at 2.

228. Notice and Order for a Hearing, Holding Company Act Release No. 27886 (Aug. 30, 2004).

229. Mirant refers to Mirant Corp. or to Mirant Corp. and its affiliated debtors as the context requires.

230. The facts in the background section are derived from *In re Mirant Corp.*, 303 B.R. 304 (N.D. Tex. 2003); *In re Mirant Corp.*, 378 F.3d 511 (5th Cir. 2004); and *In re Mirant Corp.*, 318 B.R. 100 (N.D. Tex. Dec. 9, 2004).

order, later converted to a preliminary injunction, that prohibited the FERC from taking any action or encouraging any other person or entity to take any action, to require Mirant to abide by the terms of the agreement that Mirant was seeking to reject. On October 9, 2003, the district court withdrew reference of the matter to the bankruptcy court.

Mirant (then known as Southern Energy, Inc.) and PEPCO entered into an Asset Purchase and Sale Agreement for Generating Plants and Related Assets (APSA) on June 7, 2000, pursuant to which PEPCO sold its generating assets and PPAs to Mirant. Some of the counterparties to the PPAs refused to consent to the assignment of their agreements by PEPCO. The APSA provided that if a PPA could not be assigned, PEPCO would remain liable to pay for and take delivery of power under the unassigned agreement and Mirant would receive from PEPCO all power thus delivered and reimburse PEPCO for its payments. This portion of the APSA is referred to as the Back-to-Back Agreement and is the agreement that Mirant desired to reject. This motion to reject has now been the subject of two district court and one circuit court decisions.

*A. District Court – December 23, 2003*

In the first proceeding, Mirant asserted that it had determined the Back-to-Back Agreement was substantially burdensome to its estate and constituted an impediment to its ongoing business operations.<sup>231</sup> Mirant asserted that rejection of the Back-to-Back Agreement was well within its business judgment and that the business judgment test could be used to evaluate rejection of an executory contract.<sup>232</sup> PEPCO asserted among other things that: (1) the court lacked subject matter jurisdiction because the FPA vests exclusive jurisdiction over wholesale electric service in the FERC, and the FERC possessed exclusive jurisdiction over the APSA obligations; (2) the bankruptcy court's rejection authority was subject to FERC's regulatory powers; (3) the Back-to-Back Agreement was only part of the APSA and Mirant could not reject just part of an agreement; and (4) Mirant's business judgment analysis was deficient.<sup>233</sup> The FERC argued that it should make any determination with respect to termination of the Back-to-Back Agreement after having had an opportunity to evaluate various public interest factors.<sup>234</sup> Mirant's Creditors Committee asserted that rejection of the Back-to-Back agreement should not depend on anything other than Mirant's business judgment.<sup>235</sup> Two amici, the D.C. Office of People's Counsel and the National Association of Regulatory Utility Commissioners, supported the FERC's position.<sup>236</sup> The district court determined that the matter implicated the filed rate doctrine and that the FERC possessed exclusive authority over the pricing mechanisms in the Back-to-Back Agreement.<sup>237</sup> The

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231. *In re Mirant Corp.*, 303 B.R. at 304, 310.

232. *Id.*

233. *In re Mirant Corp.*, 303 B.R. at 311.

234. *Id.*

235. *In re Mirant Corp.*, 303 B.R. at 312.

236. *Id.*

237. *In re Mirant Corp.*, 303 B.R. 304, 313–18 (N.D. Tex. 2003).

district court denied the motion to reject and ordered Mirant to show cause why the injunctive relief granted by the bankruptcy court should not be dissolved.<sup>238</sup>

*B. Fifth Circuit Court of Appeals – August 4, 2004*

The circuit court described the issue as “whether a district court may authorize the rejection of an executory contract for the purchase of electricity as part of a bankruptcy reorganization, or whether Congress granted [the FERC] exclusive jurisdiction over these contracts.”<sup>239</sup> The court found the district court’s ruling on jurisdiction to be in error and that the district court could properly authorize rejection of an executory contract in bankruptcy.<sup>240</sup> The court concluded that “the power of [a] district court to authorize rejection of the Back-to-Back Agreement [did] not conflict with the authority given to FERC to regulate rates for the interstate sale of electricity at wholesale.”<sup>241</sup> The court reasoned that rejection of the Back-to-Back Agreement would have only an indirect effect on the filed rate and that the non-breaching party’s damages would be calculated using the filed rate.<sup>242</sup>

The circuit court did not, however, approve rejection of the Back-to-Back Agreement. The court stated that it was unclear whether the Back-to-Back Agreement was a separate agreement from the APSA for purposes of rejection.<sup>243</sup> “Where an executory contract contains several agreements, the debtor may not choose to reject some agreements within the contract and not others.”<sup>244</sup> The court also discussed the standard to apply to a decision to reject an executory contract in this context.

Clearly the business judgment standard normally applicable to rejection motions is more deferential than the public interest standard applicable in FERC proceedings to alter the terms of a contract within its jurisdiction. Use of the business judgment standard would be inappropriate in this case because it would not account for the public interest inherent in the transmission and sale of electricity.<sup>245</sup>

*C. District Court – December 9, 2004*

On remand the district court considered whether the Back-to-Back Agreement was a separate agreement.<sup>246</sup> The APSA provided that it was to be governed by the laws of the District of Columbia. The court opined that there was no set answer under District of Columbia laws as to when a contract was divisible, but that the decision clearly indicated that the parties’ intentions were

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238. *Id.* at 318–19.

239. *In re Mirant Corp.*, 378 F.3d 511, 514 (5th Cir. 2004).

240. *Id.* at 515.

241. *In re Mirant Corp.*, 378 F.3d at 518.

242. *Id.* at 520.

243. *In re Mirant Corp.*, 378 F.3d at 524.

244. *Id.* (quoting *Stewart Title Guar. Co. v. Old Republic Nat’l Title Ins. Co.*, 83 F.3d 735, 741 (5th Cir. 1996)).

245. *In re Mirant Corp.*, 378 F.3d 511, 525 (5th Cir. 2004).

246. *In re Mirant Corp.*, 318 B.R. 100 (N.D. Tex. Dec. 9, 2004).

paramount.<sup>247</sup> The court concluded that the Back-to-Back Agreement was not severable from the other parts of the APSA.<sup>248</sup>

Having received the benefit of the other features of the APSA, Debtors should not be permitted at this time to reject to the detriment of Pepco the burdens imposed on Debtors by the Back-to-Back feature of the APSA. Therefore, the motion for authority to reject the Back-to-Back Agreement is being denied.<sup>249</sup>

The district court went on to announce the standard that it would use to determine whether rejection of an executory contract for the purchase of electricity at wholesale would be authorized.<sup>250</sup> The court stated that the parties would know the standard to be applied if its ruling regarding the indivisibility of the Back-to-Back Agreement and the APSA were to be reversed.<sup>251</sup> The court announced its standard as follows:

To be entitled to an order authorizing rejection of the Back-to-Back Agreement, Debtors must prove that it burdens the bankrupt estates, that, after careful scrutiny and giving significant weight to comments and findings of the FERC relative to the effect such a rejection would have on the public interest inherent in the transmission and sale of electricity in interstate commerce, the equities balance in favor of rejecting the Back-to-Back Agreement, and that rejection of the Back-to-Back Agreement would further the Chapter 11 goal of permitting the successful rehabilitation of Debtors. . . . If rejection would compromise the public interest in any respect, it would not be authorized unless Debtors show that they cannot reorganize without the rejection.<sup>252</sup>

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247. *Id.* at 105.

248. *In re Mirant Corp.*, 318 B.R. at 105.

249. *Id.* at 107.

250. *In re Mirant Corp.*, 318 B.R. at 107–8.

251. *Id.* at 107.

252. *In re Mirant Corp.*, 318 B.R. 100, 108 (N.D. Tex. Dec. 9, 2004).

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