

ELECTRICITY REGULATION COMMITTEE REPORT

This report provides a survey of significant orders issued by the Federal Energy Regulatory Commission (FERC or Commission), or by United States Courts of Appeals on the review of the FERC's orders in 2005. It also provides an overview of significant provisions of the Energy Policy Act of 2005 (EPAct 2005), which provided the first substantial amendments to the Federal Power Act (FPA) in over a decade, and the FERC's implementation of that legislation in the latter part of 2005.

A. RTO Developments

In 2005, the FERC continued with its efforts to promote the development of Regional Transmission Organizations (RTOs) and organized markets. There were a number of significant developments with respect to individual RTOs, which will be discussed below.

In addition, the FERC also addressed certain issues on a generic basis. For example, the Commission issued a staff discussion paper, *Long-Term Transmission Rights Assessment*, addressing concerns that sufficient transmission rights may not be available each year to adequately protect against congestion cost exposure within organized RTO markets.¹ The policy issue presented was whether parties should be allowed to revert to some version of the prior *pro forma* Open Access Transmission Tariff (OATT) service within the RTO markets with Locational Marginal Pricing (LMP) and Financial Transmission Rights (FTR), i.e., long-term transmission rights, or whether the FTR model can be modified to provide the type of congestion cost coverage that some parties seek.

The FERC also issued a Policy Statement on Market Monitoring Units (Policy Statement) that provides guidance on the role of market monitoring units (MMUs) associated with Independent System Operators (ISOs) and RTOs as well as the coordinated roles and responsibilities of the Commission and the MMUs.² The Policy Statement makes clear that the Commission sees MMUs performing an important role in assisting the Commission in enhancing the competitiveness of ISO/RTO markets by monitoring organized wholesale markets to identify ineffective market rules and tariff provisions, proposing rule and tariff changes to the ISO/RTO that promote market competition and efficiency, identifying potential anticompetitive behavior by market participants, and providing the comprehensive market analysis critical for the Commission to make informed policy decisions. The FERC, in this Policy Statement, clarified the functions of the MMUs.

1. ISO – New England

The debate regarding the nature of, and even the need for, a locational installed capacity market (LICAP) in New England continues.³ The genesis of this debate was the so-called standard market design (NE-SMD) proposed by ISO-New England (ISO-NE). Although the FERC accepted much of ISO-NE's

1. Notice Inviting Comments on Establishing Long Term Transmission Rights in Markets with Locational Pricing, FERC Docket No. AD05-7-000, at 1 (May 11, 2005).

2. Policy Statement on Market Monitoring Units, FERC Docket No. PL05-1-000 (May 27, 2005).

3. See *Devon Power LLC*, 113 F.E.R.C. ¶ 61,075 (2005); see also *Devon Power LLC*, 111 F.E.R.C. ¶ 63,063 (2005).

market design in an order dated September 20, 2002, the Commission also called for ISO-NE to develop a mechanism that could account for locational differences in the value of installed capacity, and thus provide market-based incentives for building new generation resources where capacity was most constrained.⁴ ISO-NE filed its first LICAP proposal in a March 2004 compliance filing, which was accepted in part by the Commission in June 2004.⁵

In August 2004, ISO-NE filed a new LICAP proposal. In addition to proposing a “kinked” demand curve, rather than the previous linear demand curve, ISO-NE proposed to replace the existing system that determined the overall “contribution” a generator made to reliability. This change has been at the heart of the vehement disagreements between ISO-NE, load serving entities, and generators ever since. In total, the design proposed by ISO-NE raised significant concerns among generators that they would not be adequately compensated and would be unable to stay in business. Load serving entities, on the other hand, argued that ISO-NE’s would pay generators far too much money, while not solving any of the reliability concerns confronting the region. This is the heart of the dispute, and stems from not only concerns about impacts on ratepayers, but also the nature of “reliability” itself.

Thus, the controversy in *Devon Power* is less over the need for reliability standards (though how much reliability is “enough” has been a subtext of the debate) and the associated need for market intervention to eliminate free-riders, but rather whether those obligations can be met by establishing a separate, long-term market in which the price of installed capacity is set by supply and demand conditions. Although the details are quite technical, and addressed in voluminous testimony submitted by all of the parties to the case, the basic idea comes down to determining how an individual generator contributes to overall system reliability. In New York, for example (and under ISO-NE’s original March 2004 compliance filing), generators are compensated based on their so-called “equivalent forced outage rate – demand,” or EFORD. In essence, EFORD measures the percentage of time a generator is not available because of forced outages (as opposed to scheduled ones) over a given time period, such as a month. Under this payment scheme, a 100 MW generator with an EFORD of five percent is compensated as if it supplied $100 \times (1 - 0.05) = 95$ MW.

ISO-NE first proposed to replace this compensation system with one based on a generator’s availability to be dispatched within thirty minutes of “critical hours,” which essentially would be those where electric prices spiked relative to natural gas prices, and which would be announced by ISO-NE after the fact. After a number of parties in the case exposed some significant theoretical and operational flaws with this approach, in November 2004 ISO-NE next proposed a payment scheme based on generator’s availability during “shortage hours,” which ISO-NE defined as hours in which a special “Operating Procedure” designation is made. Moreover, ISO-NE proposed a system under which a generator’s availability in shortage hours would be monitored over time, and gradually adjusted upwards or downwards, depending on past generator performance. Although the shortage hours approach addressed some of the concerns over the ill-fated critical hours approach, many parties expressed concerns over this one as well.

4. *New England Power Pool*, 100 F.E.R.C. ¶ 61,287 at P 1 (2002).

5. *Devon Power LLC*, 107 F.E.R.C. ¶ 61,240 (2004).

In June 2005, the Commission's Administrative Law Judge (ALJ) issued the initial decision in *Devon Power*.⁶ While the ALJ accepted much of the ISO-NE proposal, such as the "kinked" demand curve and the specific cost parameters and reliability levels it was based on, she questioned the shortage hours approach. The Commission has not issued a final order in the case. Instead, the Commission ordered the parties into settlement negotiations, which are scheduled to continue until the end of January 2006.

2. PJM Interconnection, LLC

On August 31, 2005, PJM Interconnection LLC (PJM) filed modifications to its existing capacity markets to correct certain deficiencies that it believed impaired long-term reliability.⁷ The proposed modifications—referred to as the Reliability Pricing Model (RPM)—include revisions to PJM's Open Access Transmission Tariff (Tariff) and Operating Agreement, as well as the consolidation of three separate Reliability Assurance Agreements (RAA) for the east, west, and south regions into a single RAA for the entire PJM region. PJM filed the proposed modifications to the Tariff and RAA under section 205 of the FPA and the PJM Board of Managers directed PJM to file the revisions to the Operating Agreement under section 206 of the FPA. PJM initially requested that the Commission approve the proposed modifications on or before January 31, 2006 so that RPM could be implemented on or before June 1, 2006, the start of PJM's next planning year.⁸

PJM's current capacity markets include a daily capacity obligation with daily and monthly (up to twelve months) capacity credit markets designed to accommodate the introduction of retail competition. However, PJM stated that the existing capacity markets were no longer able to ensure the long-term reliability of the region.⁹ Due to a combination of load growth, generation retirements and a lack of new generation development, PJM has experienced reliability criteria violations for New Jersey and, if recent trends continue, it expects similar reliability problems to occur in the Baltimore-Washington and Delmarva Peninsula regions in the near future.¹⁰

To address deficiencies in the existing capacity markets, RPM included a four-year forward capacity procurement process that is designed to reduce the current mismatch in planning horizons between PJM's capacity markets and the regional transmission expansion planning process, thereby, eliminating the potential reliability problems arising from unplanned and unanticipated generation retirements.¹¹ PJM also proposed explicit market power mitigation rules to prevent the exercise of market power in the capacity markets.

On March 3, 2005, the Commission issued an order modifying and conditionally accepting the market-to-market protocols of the joint operating agreement between Midwest Independent Transmission System Operator, Inc.

6. 111 F.E.R.C. ¶ 63,063.

7. Letter from Paul M. Flynn et al., Attorney for PJM Interconnection, L.L.C., to the Honorable Magalie Roman Salas, Sec'y, Fed. Energy Regulatory Comm'n (Aug. 31, 2005) (transmittal letter regarding Reliability Pricing Model, Docket Nos. ER05-1410-000, EL05-148-000) [hereinafter PJM Transmittal Letter].

8. *Id.*

9. PJM Transmittal Letter, *supra* note 7.

10. *Id.*

11. PJM Transmittal Letter, *supra* note 7, at 22.

(MISO) and PJM, providing for a joint and common market between PJM and MISO (JCM), which had been submitted in late 2004.¹² However, the Commission noted that the December 30, 2004 filing did not provide the specificity "that would have allowed us to evaluate and establish priorities for individual elements of the [JCM] and timelines in which those elements can and should be achieved."¹³ Nonetheless, the Commission permitted the RTOs to focus their attention on implementing the market-to-market protocols but required the RTOs to file a more specific plan and timeline for the continued development of the JCM on or before October 31, 2005. In the report, the Commission directed the RTOs

to identify and provide narrative description of each specific element of a [JCM], and the tasks necessary for them to complete, the impediments for them to overcome, and the resulting changes necessary to their tariffs, rules, systems, and procedures to accomplish the enhanced market portal and other elements necessary to commencement of common market operations and ultimately a [JCM].¹⁴

The Commission also required the RTOs "to provide, for each element, specific timelines for accomplishing the tasks associated with each change that they identify as necessary to achieve that element and an evaluation of the expected costs and benefits associated with achieving the element."¹⁵

3. Midwest Independent Transmission System Operator, Inc.

On March 31, 2004, the MISO filed its Open Access Transmission and Energy Markets Tariff (EMT or Tariff) with the Commission.¹⁶ The MISO's EMT provides the rates, terms and conditions necessary to implement Day-Ahead and Real-Time Energy Markets with prices based on LMP, and the allocation or auction of FTRs to provide Market Participants with a hedge mechanism against Day-Ahead Energy Market costs of congestions.¹⁷ The Commission accepted the EMT through a series of orders,¹⁸ leading to the start of the MISO Energy Markets on April 1, 2005.¹⁹

The EMT governs the operation of the MISO's Energy Markets. Under the EMT, the Tariff provisions are divided into separate modules based on their subject matter and applicability. Specifically, the EMT is comprised of five modules providing the definitions of the Tariff, the general applicability of the Tariff, and the services provided by MISO pursuant to the Tariff. While each Module applies to distinct aspects of the Energy Markets and the services

12. *Midwest Indep. Transmission Sys. Operator, Inc.*, 110 F.E.R.C. ¶ 61,226 (2005).

13. *Id.* at P 73.

14. 110 F.E.R.C. ¶ 61,226 at P 76.

15. *Id.* On October 31, 2005, MISO and PJM filed an informational report in compliance with the Commission's order. It is presently pending before the Commission. 110 F.E.R.C. ¶ 61,226 at P 76.

16. See *Midwest ISO Open Access Transmission and Energy Markets Tariff*, FERC Electric Tariff, Third Revised Vol. No. 1, Original Sheet No. 1 (effective Dec. 1, 2004) [hereinafter EMT]. See generally Letter from Stephen G. Kozey, Vice President, Sec'y and Gen. Counsel, Midwest ISO, Inc., to the Honorable Magalie Roman Salas, Fed. Energy Regulatory Comm'n (Mar. 31, 2004) (transmittal letter regarding Open Access Transmission and Energy Markets Tariff, Docket No. ER04-691-000).

17. *Id.*

18. See *Midwest Indep. Transmission Sys. Operator, Inc.*, 107 F.E.R.C. ¶ 61,191 (2004); *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), *order on reh'g*, 111 F.E.R.C. ¶ 61,043 (2005).

19. See *Midwest Indep. Transmission Sys. Operator, Inc.*, 111 F.E.R.C. ¶ 61,176 at P 23 (2005).

available therein, they are nevertheless interdependent.²⁰

The key issues the MISO has experienced in its implementation and administration of the EMT regard: the FTR allocation process; the treatment of Grandfathered Agreements (GFA); the development of a resource adequacy plan; interconnection service; and transmission planning and cost allocation. Due to limitations on space, this report will only focus on the first three.

One essential element of the MISO Energy Markets, as approved by the FERC, is the MISO's system for the allocation of FTRs, and the administration of supplemental FTR auctions. The MISO's FTRs provide Market Participants a financial hedging mechanism to manage the risk of congestion costs in the Day-Ahead Energy Markets²¹. Market Participants with existing entitlements associated with certain GFAs, Point-To-Point Transmission Service, and Network Integration Transmission Service (NITS) using designated Network Resources are eligible for FTR allocation. Additionally, Market Participants may obtain FTRs through the annual and monthly FTR allocations, the annual and monthly FTR auctions, the FTR secondary market, and for new Point-To-Point Transmission Service.²²

The implementation and administration of the FTR allocation process has been the subject of various orders of the Commission issued in response to Market Participants' complaints. In *Southern Indiana Gas and Electric Co. v. Midwest Independent Transmission System Operator, Inc.*, (SIGECO), the Commission upheld the MISO's allocation of FTRs to an "Option B" GFA between Southern Indiana Gas and Electric Co. (SIGECO) and Alcoa Power Generating Inc.²³ In *Wisconsin Public Service Corp. v. Midwest Independent Transmission System Operator, Inc.* (WPSC), the Commission addressed Wisconsin Public Service Corp.'s (WPSC) complaint that the MISO inappropriately allocated FTRs for Northern State Power Co.'s (NSP) Partial Path Transmission Service by using a WPSC generator as NSP's sink point.²⁴ In *Alliant Energy Corporate Services v. Midwest Independent Transmission System Operator, Inc.* (Alliant)²⁵ and *Wisconsin Electric Power Co. v. Midwest Independent Transmission System Operator, Inc.* (WEPCO),²⁶ the Commission addressed the definition and registration of transmission entitlements to ensure such entitlements are properly reflected in the MISO's allocation of FTRs.

In the course of accepting the EMT, the Commission also addressed how grandfathered agreements (GFAs) would be treated in the Energy Markets. As

20. The first module in the EMT, Module A, contains all common tariff provisions, including defined terms used in the tariff and their meanings, provisions relating to ancillary services, the open access same-time information system, reciprocity, creditworthiness, and regulatory and dispute resolution procedures. Module B includes the provisions governing transmission service under the Tariff. Module C comprehensively addresses the operation of the Energy Markets, scheduling and congestion management mechanism. Module D sets forth the terms and conditions relating to market monitoring and mitigation measures. Finally, Module E includes the Midwest ISO's interim resource adequacy plan, codifying existing state requirements and Regional Reliability Organization standards, until a long-term solution to resource adequacy is developed through the stakeholder process. EMT, *supra* note 16.

21. *Id.*

22. EMT, *supra* note 16.

23. *S. Ind. Gas & Elec. Co.*, 110 F.E.R.C. ¶ 61,109 (2005).

24. *Wis. Pub. Serv. Corp.*, 111 F.E.R.C. ¶ 61,131 (2005).

25. *Alliant Energy Corporate Servs.*, 111 F.E.R.C. ¶ 61,499 (2005).

26. *Wis. Elec. Power Co.*, 114 F.E.R.C. ¶ 61,005 (2006).

defined in the EMT,²⁷ GFAs are contracts that were already in existence before the MISO was established on September 16, 1998.²⁸ The GFAs are listed in Attachment P to the EMT. After conducting fact-finding proceedings regarding the GFAs,²⁹ the Commission largely accepted the EMT's proposed options for treating most GFAs,³⁰ but decided to "carve out" a limited number of GFAs from the Energy Markets,³¹ i.e., exempt the latter from most EMT rules. The GFA treatment options and carve-outs were approved by the Commission for a transition period ending on February 1, 2008. No later than one year before the transition ends, the Midwest ISO is required to file with the Commission a new proposal for the treatment of any remaining GFAs.³²

Since the MISO's Energy Markets commenced on April 1, 2005, the Market Participants have operated in accordance with the Resource Adequacy provisions found in Module E of the EMT, sections 68–70.³³ These provisions generally provide: (1) that Market Participants must comply with the Resource Adequacy requirements mandated by the applicable Regional Reliability Organization (RRO) where the load serving entities are located;³⁴ (2) the MISO will work with the RROs and the applicable state commissions to evaluate the status of regional reliability and to evaluate whether RRO requirements are being met;³⁵ and (3) resources designated by a Market Participant to meet RRO requirements must meet specified requirements³⁶ and every day such resources must be offered into the Energy Markets.³⁷

The MISO and the FERC recognized, when the EMT was conditionally approved in 2004, that Module E established interim requirements until more extensive Resource Adequacy requirements could be developed with stakeholders.³⁸ Since August of 2004, the MISO has been actively involved in creating a more permanent Resource Adequacy plan for the Region.

4. Southwest Power Pool, Inc.

When the Southwest Power Pool (SPP) sought to be recognized as an RTO, it indicated that it would pursue a phased approach to market development, beginning with the development and implementation of an energy imbalance

27. EMT, *supra* note 16, at § 1.126 (citing the Grandfathered Agreements).

28. *Midwest Indep. Transmission Sys. Operator, Inc.*, 84 F.E.R.C. ¶ 61,231 (1998).

29. *Midwest Indep. Transmission Sys. Operator, Inc.*, 107 F.E.R.C. ¶ 61,191 (2004); *Midwest Indep. Transmission Sys. Operator, Inc.*, 108 F.E.R.C. ¶ 63,013 (2004).

30. EMT, *supra* note 16, at § 38.8; *Midwest Indep. Transmission Sys. Operator, Inc.*, 108 F.E.R.C. ¶ 61,236 at PP 105, 139, 223, 225, 264, 266, 274, 305 (2004); *order on reh'g*, 111 F.E.R.C. ¶ 61,042 at PP 19, 52, 105, 123, 125–26, 129, 137, 140, 217, 224, 247, 274, 297, 379 (2005); *order on reh'g*, 112 F.E.R.C. ¶ 61,311 at PP 22, 26, 53 (2005).

31. 108 F.E.R.C. ¶ 61,236 at PP 4–5, 89, 92, 94, 99–01, 130, 135, 142–43, 149–50; 111 F.E.R.C. ¶ 61,042 at PP 12, 52, 68–70, 83–100, 126, 133, 189, 213. The Commission's core directives regarding the carve-out of GFAs were incorporated into the EMT as section 38.8.4 thereof (Carved-Out GFAs).

32. EMT, *supra* note 16, at § 38.8.5.

33. *Id.* §§ 68–70.

34. EMT, *supra* note 16, at § 68.1.

35. EMT, *supra* note 16, at § 68.2.

36. *Id.* § 69.1.

37. EMT, *supra* note 16, at § 69.2.

38. *Midwest Indep. Transmission Sys. Operator, Inc.*, 108 F.E.R.C. ¶ 61,163 at P 396 (2004) ("We view Module E as a transition mechanism to bridge the gap between market startup and the implementation of a permanent RAR plan.").

service market. On June 15, 2005, SPP filed with the Commission its proposed revisions to its OATT in order to comply with the Commission's orders addressing SPP's RTO application and its previous commitments.³⁹ SPP submitted revised tariff sheets that included a proposed energy imbalance market. Aspects of its proposal included the authority for allowing SPP to order the dispatch of generating units, a proposed real-time energy imbalance service market design, and an associated market monitoring plan and a market power mitigation plan. SPP proposed that the tariff schedules implementing its energy imbalance service market be placed into effect on March 1, 2006.⁴⁰

In an order issued on September 19, 2005, the Commission rejected the SPP filing.⁴¹ Although finding that SPP had made progress in developing its imbalance market and market monitoring and mitigation plans, its proposed tariff provisions required significant modification or elaboration before the Commission could determine whether its imbalance market was designed properly so as to allow for stable market operations. The FERC provided guidance on several issues considered critical to the success and monitoring of SPP's imbalance market, including (1) reliable and stable market operations; (2) market-based rates; and (3) mitigation and monitoring provisions.⁴²

As part of its overall development as an RTO, SPP was also required to submit certain modifications to its Bylaws and Membership Agreement. On August 9, 2005, SPP filed revised tariff sheets to amend its Bylaws and Membership Agreement in three respects.⁴³ On October 7, 2005, the Commission accepted the majority of SPP's proposals but determined that SPP needed to make a compliance filing in order to address certain deficiencies.⁴⁴

In the Commission's initial order addressing SPP's RTO application, it directed SPP to develop and file a transmission cost allocation plan by the end of 2004. "On February 28, 2005, as amended on March 1, 2005, [SPP] submitted proposed revisions to its [OATT] in order to implement a regional transmission cost allocation plan with regard to new transmission upgrades (cost allocation plan)."⁴⁵ The Commission conditionally accepted the proposed revisions and made them effective May 5, 2005, as requested by SPP. SPP was directed to submit a compliance filing within thirty days of the date of the order, which it did on May 23, 2005.⁴⁶ To date, no formula rates have been filed and SPP members are in the process of developing these rates.

5. California Independent System Operator Corporation

The California Independent System Operator Corporation (CAISO)

39. Letter from Michael E. Small, Attorney for Southwest Power Pool, Inc., to the Honorable Magalie Roman Salas, Sec'y, Fed. Energy Regulatory Comm'n (June 15, 2005) (transmittal letter regarding Open Access Transmission Tariff, Docket No. ER05-1118-000).

40. *Id.*

41. *Sw. Power Pool, Inc.*, 112 F.E.R.C. ¶ 61,303 (2005).

42. *Id.*

43. Letter from Matthew K. Segers et al., Attorneys for Southwest Power Pool Inc., to the Honorable Magalie Roman Salas, Sec'y, Fed. Energy Regulatory Comm'n (Aug. 9, 2005) (transmittal letter proposing amendments to Bylaws and Membership Agreement, Docket Nos. RT04-1-014, ER04-48-014).

44. *Sw. Power Pool, Inc.*, 113 F.E.R.C. ¶ 61,014 (2005).

45. *See Sw. Power Pool, Inc.*, 111 F.E.R.C. ¶ 61,118 at P 1 (2005).

46. 111 F.E.R.C. ¶ 61,118.

continues to develop its market redesign. The Commission issued several orders on the market redesign proposal in 2005. In June and July 2005, the Commission issued a series of orders approving several key structural changes in the California electricity market. The Commission approved the conceptual elements of the CAISO's market redesign and technology update proposal,⁴⁷ determined that the CAISO's governing board was sufficiently independent,⁴⁸ authorized the market monitoring unit of the CAISO to administer the enforcement protocol provisions of the CAISO tariff,⁴⁹ and accepted the CAISO's generation interconnection compliance filing.⁵⁰ The Commission also issued guidance on the universe of existing transmission service contracts that will be in place after the CAISO market redesign is in place.⁵¹ The development of the CAISO market redesign will likely continue until implementation, currently scheduled for 2007.

B. Transmission Developments

1. Generator Interconnection

a. Large Generators – Order No. 2003-C

Concluding an effort it began in 2003, on June 16, 2005, the FERC issued its last order on rehearing regarding Order No. 2003, which governs the interconnection of large generating facilities (over twenty megawatts) to the transmission grid.⁵² In Order No. 2003-C, the Commission considered several remaining issues raised in requests for rehearing or clarification of Order No. 2003-B. Most notably, the FERC reaffirmed several aspects of the crediting and cost recovery provisions in Order No. 2003 for an Interconnection Customer's upfront payment for Network Upgrades. In particular, the Commission retained provisions requiring a Transmission Provider to make a full lump sum reimbursement to an Interconnection Customer for its upfront payment of Network Upgrade costs within twenty years of the Commercial Operation Date of the facility, if the customer has not received full reimbursement in the form of credits against its transmission service bills.⁵³ Additionally, the FERC clarified that the obligation to provide credits for transmission service and make a lump sum payment at the twenty year mark for the upfront Network Upgrade costs paid by the Interconnection Customer applies to Affected System Operators as

47. *Cal. Indep. Sys. Operator Corp.*, 112 F.E.R.C. ¶ 61,013 (2005). After a technical conference in September, the Commission issued an order on rehearing of these issues, clarifying several of its findings. *Cal. Indep. Sys. Operator Corp.*, 113 F.E.R.C. ¶ 61,151 (2005).

48. *Cal. Indep. Sys. Operator Corp.*, 112 F.E.R.C. ¶ 61,010, *reh'g denied*, 112 F.E.R.C. ¶ 61,337 (2005).

49. *Cal. Indep. Sys. Operator Corp.*, 112 F.E.R.C. ¶ 61,001 (2005).

50. *Cal. Indep. Sys. Operator Corp.*, 112 F.E.R.C. ¶ 61,009 (2005).

51. *Cal. Indep. Sys. Operator Corp.*, 112 F.E.R.C. ¶ 61,007 (2005), *reh'g pending*.

52. Order No. 2003, *Standardization of Generator Interconnection Agreements and Procedures*, F.E.R.C. STATS. & REGS. ¶ 31,146, 68 Fed. Reg. 49,846 (2003) (to be codified at 18 C.F.R. pt. 35) [hereinafter Order No. 2003], *order on reh'g*, Order No. 2003-A, F.E.R.C. STATS. & REGS. ¶ 31,160, 69 Fed. Reg. 15,932 (2004) (to be codified at 18 C.F.R. pt. 35) [hereinafter Order No. 2003-A], *order on reh'g*, Order No. 2003-B, F.E.R.C. STATS. & REGS. ¶ 31,171, 70 Fed. Reg. 265 (2005) (to be codified at 18 C.F.R. pt. 35) [hereinafter Order No. 2003-B], *order on reh'g*, Order No. 2003-C, F.E.R.C. STATS. & REGS. ¶ 31,190, 70 Fed. Reg. 37,661 (2005) (to be codified at 18 C.F.R. pt. 35) [hereinafter Order No. 2003-C].

53. Order No. 2003-C, *supra* note 52, at P 9.

well as Transmission Providers.⁵⁴ The Commission further clarified that not every operator of a jointly-owned transmission system would be subject to the reimbursement obligation, and particularly noted that the transmission system operator's responsibility to flow through credits and reimburse the Interconnection Customer for its upfront Network Upgrade costs "does not extend beyond its normal duties as the tariff administrator."⁵⁵ Finally, the Commission denied requests for rehearing and maintained its policy that the Transmission Provider must provide transmission service credits even when the Interconnection Customer redirects its firm service on a non-firm basis over secondary receipt points other than the generating facility at issue.⁵⁶

The FERC ruled on several other issues in Order No. 2003-C. For example, the Commission reaffirmed its decision to require the Transmission Provider to pay a non-affiliated Interconnection Customer for providing reactive power within the established range if it pays its own, affiliated generators for that service.⁵⁷ The Commission also denied rehearing of its jurisdictional determinations with regard to "dual-use" facilities (i.e., transmission facilities used for sales at both wholesale and retail), particularly its prior conclusion that Order No. 2003 extended only to interconnections to dual-use facilities for the purpose of making a wholesale sale, because such facilities are subject to an open access transmission tariff. Specifically, the FERC declined to exercise jurisdiction over wholesale generator interconnections to "local distribution" facilities not previously used for wholesale sales, concluding that adopting this broader interpretation of its authority would cross the jurisdictional lines established in the FPA, in part because it could result in the "involuntary conversion" of a transmission facility once subject to the exclusive jurisdiction of a state to a facility subject also to the FERC's jurisdiction.⁵⁸

b. Small Generators – Order Nos. 2006 and 2006-A

Following up on a 2003 Notice of Proposed Rulemaking, the Commission issued a Final Rule on small generator interconnection in May 2005.⁵⁹ Very similar to Order No. 2003, Order No. 2006 adopted standard interconnection procedures and a standard interconnection agreement for inclusion in the tariffs of all public utilities, this time for generators with a capacity of no more than twenty megawatts. The procedures and agreement in Order No. 2006 were largely developed by a set of joint commenters who filed consensus positions, with some adjustments in the final rule by the FERC, which also considered a National Association of Regulatory Utility Commissioners (NARUC) model.⁶⁰

54. *Id.* at P 13. The Commission also clarified that, so long as the Interconnection Agreement remains in full force and effect, an affected system's reimbursement obligation continues even if the generating plant ceases commercial operation before the Interconnection Customer is reimbursed. Order No. 2003-C, *supra* note 52, at P 14.

55. *Id.* at P 18.

56. Order No. 2003-C, *supra* note 52, at P 22.

57. *Id.* at P 42.

58. Order No. 2003-C, *supra* note 52, at P 51.

59. Order No. 2006, *Standardization of Small Generator Interconnection Agreements and Procedures*, F.E.R.C. STATS. & REGS. ¶ 31,180, 70 Fed. Reg. 34,189 (2005) (to be codified at 18 C.F.R. pt. 35) [hereinafter Order No. 2006], *order on reh'g*, Order No. 2006-A, F.E.R.C. STATS. & REGS. ¶ 31,196, 70 Fed. Reg. 71,760 (2005) (to be codified at 18 C.F.R. pt. 35) [hereinafter Order No. 2006-A].

60. Order No. 2006, *supra* note 59, at PP 16–25.

The standard interconnection procedures adopted for small generators in Order No. 2006 provided three tracks for evaluating an interconnection request.⁶¹ The first track, termed the "Study Process," follows a somewhat simplified version of the four-step process of studies used for large generators in Order No. 2003. A second track, termed the "Fast Track Process," uses simpler technical screens for small generators no larger than two megawatts. The third track (the 10 kW Inverter Process) uses the same screens to evaluate inverter-based small generators no larger than ten kilowatts.⁶²

The standard interconnection agreement for small generators is similar in many respects to Order No. 2003's large generator interconnection agreements, but includes some streamlined and simplified provisions added at the request of commenters on FERC's proposal, who argued that it was too complex for many owners of small generators.⁶³ Order No. 2006 also adopted the same pricing policy for Network Upgrades as that adopted in Order No. 2003, requiring the generator to fund the costs of such upgrades initially, with the transmission provider then reimbursing the generator.⁶⁴

c. Wind Generators – Order Nos. 661 and 661-A

During 2005, the FERC also addressed the interconnection of wind generating plants. In Order No. 2003-A, the Commission noted that the standard interconnection rules it adopted in Order No. 2003 were largely drafted around the needs of traditional synchronous generating facilities, and that for non-synchronous technologies (such as wind), a different approach to certain interconnection requirements or procedures might be warranted.⁶⁵ Accordingly, the Commission added to the standard interconnection agreement adopted in Order No. 2003 a blank "Appendix G" as a placeholder for the future adoption of requirements specific to non-synchronous generating technologies.⁶⁶

Order No. 661, issued in June 2005, adopted a few technical interconnection requirements and interconnection procedures specific to wind plants, for inclusion in Appendix G.⁶⁷ Specifically, Order No. 661 adopted a "low-voltage ride-through" standard for wind plants, which if applicable requires that a wind plant be capable of staying online for minimum time periods (at specified voltage levels) during a voltage disturbance on the grid.⁶⁸ Order No. 661 also adopted a reactive power standard for wind plants, which if applicable would require that they maintain a power factor in the range of 0.95 leading to

61. *Id.* at P 2.

62. Order No. 2006, *supra* note 59, at P 2.

63. *Id.* at P 39. For example, the small generator agreement does not include requirements for interconnection customers to hold multiple types of insurance, and includes streamlined dispute resolution provisions. Order No. 2006, *supra* note 59, at P 39.

64. The FERC noted, however, that it expected few small generator interconnections would require upgrades. *Id.* at P 40.

65. Order No. 2003-A, *supra* note 52, at P 407.

66. *Id.*

67. Order No. 661, *Interconnection for Wind Energy*, F.E.R.C. STATS. & REGS. ¶ 31,186, 70 Fed. Reg. 34,993 (2005) (to be codified at 18 C.F.R. pt. 35) [hereinafter Order No. 661]; *order on reh'g*, Order No. 661-A, F.E.R.C. STATS. & REGS. ¶ 31,198, 70 Fed. Reg. 75,005 (2005) (to be codified at 18 C.F.R. pt. 35) [hereinafter Order No. 661-A].

68. Order No. 661, *supra* note 67, at PP 26–37. Previously, wind plants would normally trip offline during voltage disturbances. *Id.*

0.95 lagging.⁶⁹ In a change from its proposed rule,⁷⁰ Order No. 661 requires a wind plant to meet these standards only in cases where the transmission provider can show, in the System Impact Study, that such requirements are necessary for safety or reliability.⁷¹ Additionally, Order No. 661 adopted a requirement that wind plants (in all cases) provide supervisory control and data acquisition capability “to transmit data and receive instructions” from the transmission provider.⁷² For these technical requirements, Order No. 661 included a transition period, which provides that such requirements apply only to interconnection agreements signed or filed with the FERC on or after January 1, 2006. Order No. 661 also included special interconnection procedures that, according to the Commission, take into account certain technical differences in the siting, planning and interconnection of wind plants that require them to receive certain data prior to submitting a detailed plant design.⁷³ Specifically, those procedures allow a wind plant to submit an interconnection request with a set of preliminary design specifications, as opposed to complete specifications, and enter the queue and receive the base case data as provided in Order No. 2003.

In December 2005, the Commission issued an order on rehearing (Order No. 661-A). In that order, the Commission affirmed the reactive power standard it adopted in Order No. 661, as well as the case-by-case application of that standard, over the objections of certain transmission providers and the North American Electric Reliability Council (NERC).⁷⁴ The Commission also affirmed the special interconnection procedures adopted in Order No. 661.

Order No. 661-A granted rehearing in one important respect. At the urging of the NERC, and after discussions between the NERC and representatives of the wind power industry, the FERC revisited the low-voltage ride-through provisions in Order No. 661.⁷⁵ Those revisions require, beginning with interconnection agreements signed on or after January 1, 2007, that wind plants stay online for a clearing time of nine cycles when voltage drops to zero. For 2006, the NERC/AWEA revisions adopted by the Commission apply a low-voltage ride-through standard roughly equivalent to that adopted in Order No. 661. Importantly, Order No. 661-A reversed the case-by-case approach to low-voltage ride-through adopted in Order No. 661, and requires low-voltage ride through of all wind plants.⁷⁶

2. EPA 2005 –Transmission-Related Provisions and FERC Implementation

The EPA 2005 contains several provisions related to the nation’s electric transmission system. Certain significant provisions are discussed below.

69. Order No. 661, *supra* note 67, at PP 50–57.

70. Notice of Proposed Rulemaking, *Interconnection for Wind Energy and Other Alternative Resources*, F.E.R.C. STATS. & REGS. ¶ 32,579, 70 Fed. Reg. 4791 (2005).

71. Order No. 661, *supra* note 67.

72. The Commission clarified that this requirement did not authorize the transmission provider to control a wind plant. Order No. 661, *supra* note 67, at P 80.

73. *Id.* at P 97.

74. Order No. 661-A, *supra* note 67, at PP 41–46.

75. *Id.* at PP 31–35.

76. Order No. 661-A, *supra* note 67.

a. Backstop Siting Authority

Section 1221 of EAct 2005 adds a new section 216 to the Federal Power Act, providing a process for federal "backstop" authority to approve the siting of transmission facilities in certain "national interest electric transmission corridor" when States refuse to site such facilities.⁷⁷ Under new section 216(a), the Secretary of Energy is required to, within one year, conduct a study of transmission system congestion, in consultation with any affected States, to identify "any geographic area experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers," and designate such areas as national interest electric transmission corridors.⁷⁸ Section 216(b) provides that the FERC, after notice and an opportunity for hearing, may issue permits for the construction or modification of transmission facilities in national interest corridors, provided certain criteria are met. Specifically, the Commission must find either (a) that a State in which the facilities are to be located does not have authority to approve the siting of facilities or consider the interstate benefits of proposed transmission facilities; (b) that the applicant for a permit does not qualify to apply for siting approval with the relevant State because it does not serve customers in that State; or (c) a State with authority to approve the siting of the facilities has withheld approval of more than one year or has conditioned its approval in such a manner that the facilities will not significantly reduce congestion, or will not be economically feasible.⁷⁹ The Commission must also make several other findings, including findings that the facilities will be used for the transmission of electric energy in interstate commerce, and that the facilities are consistent with the public interest, will reduce congestion and protect or benefit consumers, and maximize the transmission capabilities of existing towers or structures. Section 216 further requires the FERC to issue rules specifying the form and content of applications for siting approval, and afford each State where the facilities will be located and each affected Federal agency, Indian tribe, private landowner and other interested person an opportunity to comment.⁸⁰

Additionally, section 216 grants the right of eminent domain to holders of permits approved by the FERC under that section. The legislation also designates the Department of Energy as lead agency for coordinating all Federal authorizations and environmental reviews of the transmission facilities. Section 216 also gives the "consent of Congress" for three or more contiguous States to enter into an interstate compact creating a regional transmission siting agency, subject to approval by Congress.⁸¹ Such agencies have the authority to permit siting of transmission facilities, including facilities in national interest corridors.

b. Open Access by Unregulated Transmitting Utilities

Section 1231 of the EAct 2005 adds a new section 211A to the FPA,

77. Energy Policy Act of 2005, Pub. L. No. 109-58, § 1221, 119 Stat. 594.

78. *Id.* Section 216(a) lists several factors that may be considered in designated national interest corridors, including the economic impact of the congestion, whether diversification of electric supply is warranted, and whether designation of a corridor is in the interest of national energy policy, national defense and homeland security. Energy Policy Act of 2005 § 1221.

79. *Id.*

80. Energy Policy Act of 2005 § 1221.

81. *Id.*

dealing with open access by unregulated transmission utilities.⁸² Specifically, new section 211A provides that the Commission may require an unregulated transmission utility⁸³ to provide transmission services at rates comparable to those it charges itself, and on terms and conditions that are comparable to those it operates under when providing transmission service to itself and that are not unduly discriminatory or preferential. Exempted from this provision are unregulated transmitting utilities that sell 4,000,000 megawatt hours of electricity or less per year, do not own or operate any transmission facilities (or portions thereof) that are necessary for the operation of an interconnected transmission system, or meet other criteria that the FERC determines are in the public interest.⁸⁴ The FERC may terminate this exemption as to a specific utility if it finds, under the reliability standards established pursuant to section 215 of the FPA, that the exemption will unreasonably impair continued reliability. Additionally, section 211A applies, for purposes of that section, the rate changing procedures of subsections (c) and (d) of section 205 to unregulated transmitting utilities, and allows the Commission to remand transmission rates to an unregulated transmitting utility for review and revision. Notably, this new section expressly states that it does not authorize the FERC to require an unregulated transmitting utility to join a transmission organization.⁸⁵

c. Native Load Service Obligations/Long-Term Transmission Rights

Section 1233 of the Energy Policy Act of 2005 adds a new section 217 to the Federal Power Act, containing several provisions concerning native load service obligations.⁸⁶ First, new section 217(b)(1) and (2) provides that any load-serving entity holding transmission rights and generation (or the rights to the output of generation) as of the date of enactment is “entitled to use” the transmission rights (or equivalent tradable or financial rights) it holds to deliver the output of its generating facilities or its purchased energy, to the extent necessary to satisfy its service obligations.⁸⁷ Under section 217(b)(3), in the event that all or a portion of the service obligation covered by the transmission rights described above is transferred to another load-serving entity, the transmission rights also transfer to the successor load-serving entity. Section 217(b)(4), in turn, requires the FERC to exercise its authority under the FPA to facilitate the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy their service obligations. The FERC is also required to enable load-serving entities to secure long-term firm transmission rights (or equivalent tradable or financial rights) for long-term

82. Energy Policy Act of 2005, Pub. L. No. 109-58, § 1231, 119 Stat. 594.

83. “Unregulated transmitting utility” is defined as an entity that (a) owns or operates facilities used for transmission in interstate commerce, and (b) is described in section 201(a) of the Federal Power Act. *Id.*

84. Energy Policy Act of 2005 § 1231.

85. *Id.*

86. Energy Policy Act of 2005 § 1231.

87. Specifically, to be covered under this provision, the load-serving entity must have, as of the date of enactment, both (i) owned generating facilities, marketed the output of Federal generating facilities, or held rights to purchase energy under one or more wholesale contracts, for the purpose of meeting a service obligation, and (ii) held firm transmission rights for delivery of the output of its generating facility or purchased energy. *Id.* The statute defines “service obligation” as “a requirement applicable to, or the exercise of authority granted to, an electric utility, under Federal, State or local law or under long-term contracts to provide electric service to end-users or to a distribution utility.” Energy Policy Act of 2005 § 1231.

power supply arrangements either made or planned to meet their service obligations.⁸⁸

Section 217(c) provides that nothing in subsections (b)(1), (b)(2) or (b)(3) (describing the entitlement to transmission rights held on the date of enactment and the transfer of such rights to successor load-serving entities) shall affect the current allocation or auction methods, or any future allocation or auction methods, used by a transmission organization to distribute transmission rights if it was authorized by the Commission to allocate or auction financial transmission rights as of January 1, 2005.⁸⁹ That subsection further provides that if a transmission organization never allocated financial transmission rights for a period before January 1, 2005, any application by that transmission organization to change its allocation methodology must be consistent with the FPA. Furthermore, firm transmission rights held by a load-serving entity as of January 1, 2005, must be consistent with subsections (b)(1), (b)(2) and (b)(3) of section 217.⁹⁰ In practice, this provision applies to the MISO.

New section 217 contains several other provisions. Most notably, subsection (d) allows the Commission to exercise its authority to make transmission rights not used to meet a service obligation available to other entities in a manner that is just and reasonable, and not unduly discriminatory or preferential.⁹¹ Also of note, subsection (f) states that nothing in section 217 provides a basis for abrogating contracts for firm transmission service in effect on the date of enactment.⁹²

d. Incentive-based Rates for Transmission Facilities

Section 1241 of the EPAct 2005 enacts a new section 219 of the FPA concerning transmission infrastructure development.⁹³ Section 219 requires the FERC to establish by rule, not later than one year after enactment of EPAct 2005, "incentive-based (including performance-based) rate treatments for the transmission of electric energy in interstate commerce"⁹⁴ The legislation requires the FERC's rule to include provisions that promote capital investment in the enlargement, improvement, maintenance, and operation of transmission facilities, "provide a return on equity that attracts new investment in transmission facilities," and encourage deployment of transmission technologies that increase the capacity and efficiency of existing facilities.⁹⁵ Additionally, the rule must allow public utilities to recover all prudently incurred costs for complying with mandatory reliability standards (promulgated under new section 215 of the FPA), and all costs related to the development of transmission infrastructure under the backstop siting authority provisions of section 216 of FPA (discussed above). Further, new section 219 requires the Commission to "provide incentives to each

88. Energy Policy Act of 2005, Pub. L. No. 109-58, § 1231, 119 Stat. 594. Section 1233(b) of the EPAct requires that the FERC, within one year, implement this provision in transmission organizations with organized electricity markets. *Id.* § 1233(b).

89. Energy Policy Act of 2005 § 1233.

90. *Id.*

91. Energy Policy Act of 2005 § 1233(d).

92. *Id.* § 1233.

93. Energy Policy Act of 2005, Pub. L. No. 109-58, § 1241, 119 Stat. 594.

94. *Id.*

95. Energy Policy Act of 2005 § 1241.

transmitting utility or electric utility that joins a Transmission Organization,” and permits recovery of any costs incurred in providing such incentives through the transmission rates of the specific utility or the transmission rates of the transmission organization.⁹⁶ Finally, section 219 states that all rates approved under the rules adopted by the Commission must meet the just and reasonable and not unduly discriminatory standards of section 205 and 206 of the FPA.⁹⁷

On November 18, 2005, the Commission issued a Notice of Proposed Rulemaking (NOPR) which is required by the new section 219 of the FPA.⁹⁸ The NOPR proposes a new section 35.35 of the Commission’s regulations, which would describe certain incentive-based rate treatments for transmission infrastructure investments that the FERC would approve, and that it believes meet the objectives outlined in section 219. The proposed regulations describe incentive-based rate treatments available to all public utilities, incentives available only to stand-alone transmission companies (or transcos), and incentives for joining a transmission organization, as defined in the FPA.⁹⁹

In particular, for all public utilities (including transcos), the Commission proposed to consider incentive-based return on equity levels for new transmission facilities that provide benefits to consumers “by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion.”¹⁰⁰ To reduce the impacts on utility cash flows from transmission investment projects, the NOPR also proposed to consider, on a case-by-case basis, permitting a public utility (including a transco) to include 100% of construction work in progress expenses in rate base, and to permit pre-commercial operations costs associated with new transmission projects to be expensed rather than capitalized.¹⁰¹ Additionally, the proposed regulations would allow (on a case-by-case basis) an overall rate of return based on a hypothetical capital structure, with flexibility to alter that structure as necessary to maintain the viability of the project.¹⁰² Further, the NOPR proposes to allow transmission facilities to be depreciated over fifteen years, as opposed to the current practice, which allows depreciation over the useful life of the facilities.¹⁰³ The proposed regulations would also allow a public utility (including a transco) to fully recover the costs incurred for a transmission project that is later “cancelled or abandoned due to factors beyond the control of the public utility”¹⁰⁴ Finally, the NOPR proposed to allow all public utilities currently under a retail rate moratorium to defer cost recovery for new transmission facilities, to alleviate concerns such utilities may have regarding cost recovery

96. *Id.* The act defines “Transmission Organization” as “a Regional Transmission Organization, Independent System Operator, independent transmission provider, or other transmission organization finally approved by the Commission for the operation of transmission facilities.” Energy Policy Act of 2005 § 1241.

97. *Id.*

98. Notice of Proposed Rulemaking, *Promoting Transmission Investment through Pricing Reform*, F.E.R.C. STATS. & REGS. ¶ 32,593, 70 Fed. Reg. 71,409 (2005) [hereinafter *Promoting Transmission Investment*].

99. *Id.*

100. *Promoting Transmission Investment*, *supra* note 98, at P 22.

101. *Id.* at P 23.

102. *Promoting Transmission Investment*, *supra* note 98, at P 29.

103. *Id.* at P 23.

104. *Promoting Transmission Investment*, *supra* note 98, at P 34.

during the rate freeze.¹⁰⁵

Specific to transcos, the NOPR proposed two specific incentives.¹⁰⁶ First, noting its belief that the formation of more transcos will promote increased transmission system investment, the FERC proposed to permit transcos to receive a higher return on equity “that both encourages transco formation and is sufficient to attract investment.”¹⁰⁷ Second, to remove any disincentives to sell transmission assets to a transco that may result from concerns over the recovery of income taxes, the Commission stated that it would consider proposals to include in rates any adjustments for accumulated deferred income taxes when a transco is purchasing transmission facilities.¹⁰⁸

The Commission also proposed to continue considering requests to give return on equity incentives to utilities that join an RTO or ISO.¹⁰⁹ The FERC also sought comment on other options for providing incentives, including consideration of one-time incentives on a case-by-case basis for specific transmission projects, and the recovery in rates of an acquisition premium for the purchase of transmission facilities by a transco.¹¹⁰ The notice further proposed to require public utilities to annually submit a report to the FERC detailing their current and projected investment activities.¹¹¹ Finally, the NOPR also sought comments on other issues, including performance-based rates for transmission, the role of public power in developing transmission infrastructure, and the use of advanced transmission technologies.¹¹² At the time of this writing, comments on the notice were being filed with the Commission.

e. Participant Funding

Section 1242 of the EPAct 2005 provides that the FERC may approve a participant funding plan (i.e., a plan whereby the costs of a transmission construction project are funded entirely by a specific transmission customer, instead of through rolled-in rates) regardless of whether the entity submitting the application for the plan is a member of a Commission-approved transmission organization, so long as the rates under the plan are just and reasonable, not unduly discriminatory or preferential, and are otherwise consistent with sections 205 and 206 of the Federal Power Act.¹¹³

105. *Id.* at P 35.

106. The NOPR defines a transco as “a stand-alone transmission company, approved by the Commission, which sells transmission service at wholesale and/or on an unbundled retail basis, regardless of whether it is affiliated with another public utility.” *Promoting Transmission Investment*, *supra* note 98, at P 37. The Commission noted that this definition would not require membership in an RTO or ISO. *Id.* at P 42.

107. *Promoting Transmission Investment*, *supra* note 98, at PP 39–40.

108. *Id.* at P 43. The FERC noted that it had already considered such proposals with regard to two transcos, International Transmission Company and Michigan Electric Transmission Company. *See Promoting Transmission Investment*, *supra* note 98, at P 43. (citing *ITC Holdings Corp.*, 102 F.E.R.C. ¶ 61,182 at P 62 (2003); *Trans-Elect, Inc.*, 98 F.E.R.C. ¶ 61,368, at p. 62,590 (2002)).

109. *Promoting Transmission Investment*, *supra* note 98, at P 45. The FERC also proposed to remove from its regulations the current provisions concerning innovative rate treatments for RTOs at 18 C.F.R. § 35.34(e) (2005). *Id.* at PP 50–52.

110. *Promoting Transmission Investment*, *supra* note 98, at PP 53–55.

111. *Id.*

112. *Promoting Transmission Investment*, *supra* note 98, at PP 56–67.

113. Energy Policy Act of 2005, Pub. L. No. 109-58, §1242, 119 Stat. 594.

3. NOI on Open Access Transmission Tariff Reform

On September 16, 2005, the Commission issued a significant Notice of Inquiry (NOI)¹¹⁴ that sought comments from the industry on the need to reform the OATT adopted by the Commission in Order No. 888.¹¹⁵ In the NOI, the FERC noted that since the adoption of Order No. 888 in 1996, there have been vast changes in the electric industry, including increased wholesale competition, the increased presence of independent buyers and sellers of power, increased regional (as opposed to local) trading of power, increased utility mergers, and the creation of independent transmission organizations.¹¹⁶ In light of these changes, the Commission stated that questions have arisen concerning the effectiveness of certain portions of the *pro forma* OATT and the OATTs of transmission providers. The FERC stated in the NOI that public utilities still have the “discretion and the incentive” to interpret and apply their OATTs in a discriminatory manner, and that the implementation discretion given to transmission providers in Order No. 888 and the *pro forma* OATT makes it difficult for the Commission to identify and remedy undue discrimination, and has led to inconsistent results across the industry.¹¹⁷ Additionally, the FERC expressed concern that undue discrimination and preferential treatment is even more difficult to detect and remedy in areas where the transmission system is constrained, and that there are more opportunities for undue discrimination in such areas.¹¹⁸

Based on the changes that have taken place in the industry since Order No. 888 was adopted, and its stated concerns about continued opportunities for undue discrimination, the FERC declared in the NOI its preliminary view that reforms to Order No. 888 are needed to prevent undue discrimination and preference in the provision of transmission service.¹¹⁹ The NOI posed several questions to the industry concerning Order No. 888 and the *pro forma* OATT. Those questions covered several subjects, including: transmission pricing, untimely processing of requests for transmission service, remedies, penalties and enforcement for OATT violations, rollover rights, joint transmission planning, the obligation to expand capacity to satisfy the needs of network service customers, curtailments, hoarding of transmission capacity, and open access by unregulated transmitting utilities under section 1231 of the EPAct 2005 (discussed above).¹²⁰ The Commission emphasized that it was not proposing to change the native load preference in Order No. 888.

4. Policy Statement on Independent Transmission Company Formation

Throughout the first half of 2005, the Commission continued to struggle to

114. Notice of Inquiry, *Preventing Undue Discrimination and Preference in Transmission Services*, F.E.R.C. STATS. & REGS. ¶ 35,553, 70 Fed. Reg. 55,796 (2005) [hereinafter *Preventing Undue Discrimination*].

115. Order No. 888, *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, [Regs. Preambles 1991–1996] F.E.R.C. STATS. & REGS. ¶ 31,036 (1996), 61 Fed. Reg. 21,540 (1996) (to be codified at 18 C.F.R. pts. 35, 385).

116. *Preventing Undue Discrimination*, *supra* note 114, at P 4.

117. *Id.* at P 5.

118. *Preventing Undue Discrimination*, *supra* note 114, at P 6.

119. *Id.* at P 8.

120. *Preventing Undue Discrimination*, *supra* note 114.

finalize a long sought transmission pricing policy statement.¹²¹ Just prior to former Chairman Pat Wood III's departure from the FERC, the Commission deferred action on a broad transmission pricing policy, and instead issued a policy statement concerning the passive ownership of independent transmission companies by market participants.¹²² Largely, the policy statement was intended to clarify FERC's willingness to consider under section 205 of the FPA, on a case-by-case basis, incentive rate treatment proposals for transcos that have market participants as passive minority equity owners.¹²³ Noting that the Commission had recently shown flexibility on the issue of minority ownership by market participants in *ITC Holdings Corp. & International Transmission Co.*,¹²⁴ the policy statement identified a non-exclusive list of relevant considerations that would be taken into account to evaluate whether market participants are in fact passive owners. The factors identified include the percentage of ownership held by the market participant(s), the composition of the board of directors, the applicant's corporate governance structure, and the applicant's capital investment policies and the relationship of those policies with the policies governing capital contributions or dividend reinvestment by passive owners.¹²⁵

The policy statement discusses some of these factors in more detail. For example, the FERC stated that when considering transcos' applications with a proposed passive ownership structure, it will "focus on the ability of the applicant to operate free of market participant control or influence."¹²⁶ Specifically, the Commission stated that it would consider proposals for passive minority ownership of up to 49% by a single market participant, and would also entertain proposals where multiple market participants owned a greater than 49% share of the transco.¹²⁷ The FERC also noted its concern over the level of voting control held by market participants, and stated that it would continue to apply a standard (first applied in *ITC Holdings*) prohibiting market participants from voting, directing or controlling 5% or more of the transco's stock.¹²⁸ With regard to the composition of the board of directors of a proposed transco, the policy statement explains that the Commission will consider the need for management to seek board approval, and the degree to which market participants can influence that approval.¹²⁹

121. See, e.g., *Wood Sees Transmission Pricing Policy by July, Calls for More Capacity*, INSIDE FERC, May 2, 2005, at 1; *Commission Decides to Focus on Expanding Transcos*, INSIDE FERC, June 20, 2005, at 1 [hereinafter *Commission Decides*].

122. *Policy Statement Regarding Evaluation of Independent Ownership and Operation of Transmission*, 111 F.E.R.C. ¶ 61,473 (2005); see also *Commission Decides*, supra note 121, at 1.

123. 111 F.E.R.C. ¶ 61,473 at P 1.

124. *ITC Holdings Corp.*, 111 F.E.R.C. ¶ 61,149 (2005).

125. 111 F.E.R.C. ¶ 61,473 at P 4. Also identified as relevant factors were executive compensation agreements and other management incentives and their role in shaping independent operation and investment decisions, and any limits on "contractual service and legacy relationships" with former affiliates who are market participants. *Id.*

126. *Policy Statement Regarding Evaluation of Independent Ownership and Operation of Transmission*, 111 F.E.R.C. ¶ 61,473 at P 5 (2005).

127. *Id.* at P 5.

128. 111 F.E.R.C. ¶ 61,473 at P 5.

129. *Id.* at P 6.

C. *Electric Reliability*

1. EPAct 2005 Provisions – Reliability and FERC Implementation

One of the more significant portions of the EPAct 2005 is section 1211, which granted the FERC authority over bulk electric system reliability.¹³⁰ A description of some of the highlights of that legislation, and the Commission's first steps to implement it, are described below.

Section 1211 of EPAct 2005 added a new section 215 to the FPA.¹³¹ Section 215(b) gives the FERC jurisdiction over an Electric Reliability Organization (ERO) to be certified by the Commission, any regional entities under the ERO, and all users and owners of the nation's bulk power system. An ERO is defined as an entity certified by the Commission for the purpose of establishing and enforcing reliability standards for the bulk-power system, subject to Commission review.¹³² Reliability standard, in turn, is defined in the act to mean a requirement approved by the Commission "to provide for the reliable operation of the bulk-power system," including requirements for existing facilities (including cyber security) and for the design of planned additions or modifications to the system that are necessary to maintain reliability.¹³³ That definition expressly excludes, however, requirements to enlarge facilities or construct new transmission capacity or generation capacity. Under the grant of jurisdiction in section 215(b), the FERC is granted jurisdiction over the ERO and other owners and users of the grid "for purposes of approving reliability standards established under this section and enforcing compliance with this section."¹³⁴ This section further requires all users, owners and operators of the bulk power system to comply with the reliability standards that ultimately take effect. Finally, section 215(b) requires that the FERC, within 180 days of the date of enactment, issue a final rule implementing its requirements.¹³⁵

Following the issuance of the required final rule, section 215(c) provides that any person may submit an application to be certified by the Commission as the ERO.¹³⁶ This section permits certification of an applicant as the ERO if the FERC finds that the applicant meets several criteria. First, the Commission must determine that the applicant "has the ability to develop and enforce . . . reliability standards that provide for an adequate level of reliability of the bulk-power system"¹³⁷ Second, the FERC must find that the applicant has established rules that will: (a) assure that it will be independent of users, owners, and operators of the grid, while also providing for fair stakeholder representation in the selection of its directors and "balanced decision-making" in its organizational structure; (b) equitably allocate dues, fees, and other charges among end users of the grid for its activities; (c) provide "fair and impartial" procedures to enforce reliability standards through penalties; (d) provide for reasonable notice and opportunity for comment, due process, and a balance of interests in developing

130. Energy Policy Act of 2005, Pub. L. No. 109-58, § 1211, 119 Stat. 546.

131. *Id.*

132. Energy Policy Act of 2005 § 1211.

133. *Id.*

134. Energy Policy Act of 2005 § 1211(b).

135. *Id.* § 1211.

136. Energy Policy Act of 2005, Pub. L. No. 109-58, § 1211, 119 Stat. 594.

137. *Id.*

reliability standards and performing its other duties; and (e) provide that it will take appropriate steps (after consultation) to gain recognition in Canada and Mexico.¹³⁸

After certification, the ERO must file each of its reliability standards (and later, any modifications to already-approved reliability standards) with the FERC.¹³⁹ New section 215(d)(2) provides that the Commission may either approve a reliability standard or reject and remand it to the ERO for further consideration. Under that subsection, the Commission may approve a reliability standard if it finds that the standard is "just, reasonable, not unduly discriminatory or preferential, and in the public interest."¹⁴⁰ In considering proposed reliability standards, the FERC must give weight to the technical expertise of the ERO or an interconnection-wide regional entity under the ERO, but is not to give such weight when considering the effect of a proposed standard on competition.¹⁴¹ The Commission is also given authority to order the ERO to submit a proposed reliability standard or modification to a reliability standard addressing a specific matter, if necessary. The statute requires the FERC to have fair procedures for identifying and resolving a conflict between a reliability standard and any terms, conditions, or rates approved or ordered by the Commission for a transmission organization.¹⁴²

Under new section 215(e), the ERO may assess penalties for violation of an approved reliability standard, after notice and an opportunity for a hearing.¹⁴³ Additionally, the Commission may upon its own motion or complaint order compliance with a reliability standard, and may also impose penalties (after notice and an opportunity for a hearing) for violation of a reliability standard. Penalties assessed by the ERO, a regional entity under the ERO (discussed below) or the Commission must bear a "reasonable relation to the seriousness of the violation."¹⁴⁴

The FERC is required under this new subsection to issue regulations allowing the ERO to delegate the authority to propose and enforce reliability standards to a regional entity. Notably, the Commission and the ERO are required under the legislation to rebuttably presume that a delegation to a regional entity organized on an interconnection-wide basis should be approved.¹⁴⁵

Subsection (i) provides that nothing in section 215 authorizes the ERO or the Commission to order construction of new generation or transmission capacity, or to enforce resource adequacy or safety standards.¹⁴⁶ Additionally, that subsection states that section 215 should not be construed to preempt the

138. Energy Policy Act of 2005 § 1211(c).

139. *Id.*

140. Energy Policy Act of 2005 § 1211.

141. *Id.* Section 217(d)(3) provides for a rebuttable presumption that a reliability standard, or modification to an existing reliability standard, is just, reasonable and not unduly discriminatory or preferential if it is to be applicable on an interconnection-wide basis and is proposed by a regional entity on an interconnection-wide basis. Energy Policy Act of 2005, Pub. L. No. 109-58, §1211, 119 Stat. 594.

142. *Id.*

143. Energy Policy Act of 2005 § 1211. The ERO must also file a record of the proceeding with the FERC.

144. *Id.*

145. Energy Policy Act of 2005 § 1211.

146. *Id.*

ability of a state to take action to ensure the safety, adequacy or reliability of electric service, so long as the action is not inconsistent with a reliability standard. Interestingly, New York is explicitly exempted from this provision, and may establish rules resulting in greater reliability within that state.¹⁴⁷

On September 1, 2005, the FERC issued a NOPR as required by new section 215 of the FPA.¹⁴⁸ Specifically, the NOPR proposed regulations concerning: (1) the criteria to qualify to be certified as the ERO, (2) procedures regarding enforcement of reliability standards by the ERO and the FERC, (3) criteria governing the delegation of authority to a regional entity under the ERO, (4) procedures for establishing regional advisory bodies to advise the FERC, the ERO or a regional entity, (5) the preparation of periodic reliability reports by the ERO concerning the reliability of the North American transmission system, and (6) the funding of the ERO.¹⁴⁹

For the most part, the FERC characterized the proposed regulations as straightforward implementations of the text of new section 215 of the FPA. The NOPR did raise a number of issues regarding the interpretation of section 215 of the FPA and other questions regarding the new reliability legislation. The following summarizes a few of those issues, but is certainly not an exhaustive list of questions and issues raised by the NOPR.

For example, the FERC stated that it interpreted section 215 to require the ERO to meet the criteria for certification on an ongoing basis, and that violation of such criteria would amount to a violation of the FPA.¹⁵⁰ As a result, the Commission proposed to periodically audit the ERO, and to suspend the ERO's certification if violations of the certification criteria are found.¹⁵¹ The Commission also proposed to require the ERO to periodically submit an application for recertification as the ERO, and sought comments on a reasonable length of time for recertification.¹⁵²

With regard to approval of reliability standards, the NOPR explained that the Commission interprets section 215(d)(2) and (d)(3) to not require it to give weight to the technical determinations of regional entities not organized on an interconnection-wide basis, or to require it to presume the reasonableness of a reliability standard proposal by such regional entities.¹⁵³ The FERC further stated that it "expects a greater level of uniformity among [r]eliability [s]tandards approved for [r]egional [e]ntities not organized on an [i]nterconnection-wide basis."¹⁵⁴ Additionally, the Commission expressed concern that because it may only accept or remand a reliability standard, there could be periods of time where there is no mandatory reliability standard in place in a particular area. To address this possibility, the FERC proposed regulations that would allow it to

147. Energy Policy Act of 2005, Pub. L. No. 109-58, § 1211, 119 Stat. 594.

148. Notice of Proposed Rulemaking, *Rule Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, F.E.R.C. STATS. & REGS. ¶ 32,587, 70 Fed. Reg. 53,117 (2005) (to be codified at 18 C.F.R. pt. 38) [hereinafter *Rule Concerning Certification*].

149. *Id.* at P 1.

150. *Rule Concerning Certification*, *supra* note 148, at P 39.

151. *Id.*

152. *Rule Concerning Certification*, *supra* note 148, at P 42.

153. *Id.* at P 46.

154. *Rule Concerning Certification*, *supra* note 148, at P 46.

state a deadline for revisions when it remands a reliability standard.¹⁵⁵

The NOPR raised several issues and questions regarding the enforcement of reliability standards and penalties for violation of such standards. Among those issues, the FERC declared its belief that penalties "should not be limited to monetary penalties and may include limitations on activities, functions, operations, or other appropriate sanctions, including the establishment of a publicly available reliability watch list composed of major violators."¹⁵⁶ The Commission also stated that it may consider compliance audits, or the installation of Commission staff onsite, with regard to entities with a large amount of violations or who have committed serious violations. Finally, the FERC discussed at length the enforcement activities of other self-regulatory organizations (SROs) (such as the National Association of Securities Dealers (NASD) and related organizations), including their procedures for appealing disciplinary decisions, and sought comments on this discussion and several other questions related to penalties and enforcement.¹⁵⁷

Another significant area of discussion in the NOPR concerns the delegation of authority from the ERO to a regional entity. The FERC made two interpretive statements of note here. First, the Commission stated that it interpreted section 215 as allowing a regional entity to possess delegated authority only to enforce reliability standards approved in a specific region, and noted that regional entities may propose reliability standards to the ERO as regional variances supplementing (instead of replacing) the ERO's standards.¹⁵⁸ Second, the FERC stated its belief that section 215 requires regional entities to comply with the ERO certification and delegation criteria on an ongoing basis, and that any violation of those criteria by a regional entity would constitute a violation of the FPA.¹⁵⁹ The Commission posed several questions regarding regional entity delegation, as well.

A final significant issue raised in the NOPR is funding of the ERO. The Commission noted that section 215 did not contain any specific requirements regarding funding of the ERO, stating only that the ERO, to be certified, must have established rules for allocating dues, fees, and charges among end users. The FERC stated its belief that "certainty regarding the funding of the ERO is essential for the stability and ultimate success of the organization."¹⁶⁰ The proposed regulations would require the ERO to submit its budget to the FERC for approval no later than 130 days prior to the beginning of the fiscal year, with the Commission issuing an order no later than 60 days prior to the start of the fiscal year. The Commission stated that it did not propose to dictate a funding mechanism, and would allow an ERO applicant the discretion to propose an appropriate funding mechanism.¹⁶¹ Finally, the FERC noted that the NERC is currently funded on the basis of "net energy for load," and declared that this

155. *Id.* at P 53.

156. *Rule Concerning Certification*, *supra* note 148, at P 66.

157. *Id.* at PP 68-71.

158. *Rule Concerning Certification*, *supra* note 148, at P 80.

159. *Id.*

160. *Rule Concerning Certification*, *supra* note 148, at P 99.

161. *Id.* at P 100. Specifically, the proposed regulations simply require an applicant for certification as the ERO to include a plan for allocation and assessment of dues, fees and charges. *Rule Concerning Certification*, *supra* note 148, at P 100.

funding method meets the requirements of section 215.¹⁶²

D. Market Based Rate Authority

1. Commission Requirements to Update Market Power Analysis

On May 31, 2005, the Commission announced its policy with respect to entities that failed to comply with the conditions of their market-based rate authority, specifically, the requirement to submit an updated or revised market power analysis.¹⁶³ As a condition of receiving market-based rate authority, the Commission requires market-based rate sellers to submit an updated market power analysis every three years.¹⁶⁴ The May 31 Order notified the market-based rate sellers, which had failed to comply with the updating requirement that their market-based rate authorizations would be revoked, unless each filed an updated market power analysis.

On November 3, 2005, in two separate orders,¹⁶⁵ the Commission accepted the market analysis reports of over fifty entities that filed an updated market analysis and revoked the market based rate authority of over one hundred others, which failed to comply with the Commission's order requiring updated market analyses. Chairman Joseph T. Kelliher noted, "[a]uthorization to charge market-based rates is a privilege, not a right. We will not tolerate abuse of this privilege."¹⁶⁶ The Commission terminated the market-based rate tariffs of those entities that failed to comply with the Commission's requirements. Additionally, any waivers and authorizations previously granted in connection with the market-based rate authority are no longer applicable.

2. Delivered Price Test

On October 21, 2005, the Commission issued two separate orders with similar findings relating to the Delivered Price Test (DPT), which the Commission uses for assessing market power.¹⁶⁷ The Commission determined the Cleco Companies and Kansas City Power & Light Co. (KCPL) rebutted the presumption of market power that had been established by applicant's failure to pass the indicative screens adopted in *AEP*, and satisfied the Commission's generation market power standard for market-based rate authority in the Cleco Companies home control area and the KCPL control area, respectively.¹⁶⁸

The results of the DPT analysis for Cleco Companies and KCPL in their

162. *Id.* at P 102.

163. *3E Techs., Inc.*, 111 F.E.R.C. ¶ 61,295 (2005); *Acadia Power Partners, LLC*, 107 F.E.R.C. ¶ 61,168 (2004).

164. *See, e.g., W. Res., Inc.*, 94 F.E.R.C. ¶ 61,050, at p. 61,247 (2001); *Entergy Servs., Inc.*, 58 F.E.R.C. ¶ 61,234, at p. 61,760 (1992); *PSI Energy, Inc.*, 51 F.E.R.C. ¶ 61,367, at p. 62,209 (1990).

165. *Alcan Power Mktg., Inc.*, 113 F.E.R.C. ¶ 61,123 (2005); *3E Techs., Inc.*, 113 F.E.R.C. ¶ 61,124 (2005).

166. Press Release, Fed. Energy Regulatory Comm'n, Commission Accepts Market Analysis for 50+ Companies, Revokes Market-Based Rate Authority for 100+ Others, Establishes Disgorgement of Profits (Nov. 3, 2005).

167. *AEP Power Mktg., Inc.*, 107 F.E.R.C. ¶ 61,018 at PP 105–12, 207–08 (2004), *order on reh'g*, 108 F.E.R.C. ¶ 61,026 (2004).

168. *Kan. City Power & Light Co.*, 113 F.E.R.C. ¶ 61,074 at PP 1, 45 (2005); *order of market based rates*, 113 F.E.R.C. ¶ 61,074 at PP 26–36.

respective control areas varied depending on whether the economic capacity or available economic capacity measure is used to perform the analysis. The DPT does not function like the initial indicative screens—i.e., failure of either the economic capacity or available economic capacity analyses does not result in an automatic failure of the test as a whole.¹⁶⁹ In particular, neither measure is definitive; the Commission weighs the results of both the economic capacity and the available economic capacity analyses and considers the arguments of the parties.¹⁷⁰

The Commission has recognized that not all generation capacity is available all of the time to compete in wholesale markets and that some accounting for native load requirements is warranted.¹⁷¹ In the DPT analysis, available economic capacity accounts for native load requirements. DPT results for Cleco Companies and KCPL using the available economic capacity measure indicated a lack of market power in their control area.¹⁷²

While available economic capacity reflects native load obligations in the case of assessing the potential for market power in generation, the Commission has noted that a clear distinction between generation serving native load and generation competing for wholesale load is not so easily made.¹⁷³ The Commission also considers economic capacity in assessing generation market power. The Hirschman-Herfindahl Index (HHI), using the economic capacity measure, are below the 2,500 threshold for all but one season/load period.¹⁷⁴

In addition, the DPT for Cleco Companies and KCPL indicated that the market shares using the available economic capacity measure were below 20% (with some exceptions). The HHI, using the available economic capacity measure, are all below 2,500 (with some exceptions) for both entities, and the Cleco Companies and KCPL are not pivotal using the available economic capacity measure in any season.¹⁷⁵

3. Mitigation Proposals

Several entities have decided to bypass the DPT and submitted mitigation proposals to the Commission. While, the Commission has not acted on the vast majority of the filed mitigation proposals, it has issued orders in a few specific cases. The determinations in these few cases, as summarized below, provide guidance regarding the Commission's focus in evaluating mitigation proposals.

a. Tampa Electric Company, et al.

On November 17, 2005, the Commission accepted Tampa Electric Company's (Tampa's) proposal to mitigate the presumption of generation market power in the control areas of Tampa Electric and Reedy Creek Improvement District (Reedy Creek).¹⁷⁶ Tampa had stated that it would seek prior

169. 113 F.E.R.C. ¶ 61,074 at PP 40–43.

170. *Id.*

171. 113 F.E.R.C. ¶ 61,074 at PP 40–43.

172. *Id.*

173. 113 F.E.R.C. ¶ 61,074 at PP 40–43.

174. *Kan. City Power & Light Co.*, 113 F.E.R.C. ¶ 61,074 at PP 40–43 (2005).

175. *Id.* at PP 40–43.

176. *Tampa Elec. Co.*, 113 F.E.R.C. ¶ 61,159 (2005). Tampa Electric Company (Tampa Electric) submitted the market-based rate application on behalf of itself and its affiliates, collectively referred to as

Commission authorization for any sale into the Tampa Electric control area.¹⁷⁷ The Commission interpreted Tampa's proposal to mean that such sales would be made at cost-based rates, and accepted Tampa's proposal on the condition that any such sales would be cost-justified.¹⁷⁸

While the Commission accepted Tampa's commitment to seek prior Commission authorization for any sale into the Tampa Electric control area, the Commission rejected Tampa's proposal to exclude two dynamically scheduled customers from this commitment.¹⁷⁹ "The two wholesale customers that are dynamically scheduled as part of Tampa Electric's control area are electronically included in Tampa Electric's control area."¹⁸⁰ "[A]s long as these customers, or any others, are dynamically scheduled as part of the Tampa Electric control area," the Commission concluded that, these wholesale customers

must be covered by any mitigation applicable to that control area. Similarly, if a customer that is physically located outside of Tampa Electric's control area cease[d] to be dynamically scheduled as part of the Tampa Electric control area, that customer will no longer be covered by any mitigation applicable to the Tampa Electric control area.¹⁸¹

"Tampa submitted a mitigation proposal for the Reedy Creek control area, proposing to use a currently effective cost-based rate for short-term sales into the Reedy Creek control area and to seek prior Commission authorization for long-term sales."¹⁸² The Commission noted that Tampa defined short-term sales as sales with a duration of one year or less. This definition was inconsistent with the Commission's policy to require "long-term mitigation to apply to sales of one year or longer, and short-term sales to apply to sales of less than one year."¹⁸³ Accordingly, the Commission's acceptance of Tampa's mitigation proposal for short-term sales into the Reedy Creek control area was conditioned on the application of the Commission's definition of short-term sales.¹⁸⁴ The Commission accepted Tampa's "commitment to seek prior authorization for long-term sales to the extent that such commitment applies to sales of one year or longer."¹⁸⁵ Further, the Commission interpreted "Tampa's proposal to be that such sales will be made at cost-based rates and [the Commission] accept[ed] Tampa's proposal on the condition that any such sales will be cost-justified."¹⁸⁶

The Commission determined that "Tampa's proposal to limit the mitigation in the Reedy Creek control area to the winter season only [was] misplaced."¹⁸⁷ "The winter season was not the only season in which Tampa's market share exceeds 20[%.]"¹⁸⁸ While the Commission conditionally accepted Tampa's proposal for the winter season, it directed Tampa to submit a filing to inform the

"Tampa."

177. 113 F.E.R.C. ¶ 61,159.

178. *Id.* at P 31.

179. 113 F.E.R.C. ¶ 61,159 at P 31.

180. *Id.*

181. 113 F.E.R.C. ¶ 61,159 at P 31.

182. *Tampa Elec. Co.*, 113 F.E.R.C. ¶ 61,159 at P 39 (2005).

183. *Id.* at P 39.

184. 113 F.E.R.C. ¶ 61,159 at P 39.

185. *Id.*

186. 113 F.E.R.C. ¶ 61,159 at P 39.

187. *Id.* at P 40.

188. *Tampa Elec. Co.*, 113 F.E.R.C. ¶ 61,159 at P 40 (2005).

Commission whether it would extend its current proposal to the other three seasons, or accept the default cost-based rates or other cost-based rates for the other three seasons.¹⁸⁹

b. Alliant Energy Corporate Services, Inc.

On September 19, 2005, the Commission accepted "Alliant Energy Corporate Services, Inc.'s (Alliant) mitigation proposal, and [found] that the start of the [MISO] markets obviate[d] the need for further investigation into Alliant's generation market power in the Dairyland control area."¹⁹⁰ In addition, the Commission concluded because of the unique circumstances, "Alliant's proposed mitigation measures for the Alliant-East, Alliant-West and Dairyland control areas for the period between the refund effective date and the April 1, 2005 start of the [MISO] markets satisfie[d]" the Commissions concerns.¹⁹¹

Alliant proposed mitigation measures designed to eliminate any potential to exercise generation market power in the Alliant-East, Alliant-West or Dairyland control areas prior to the commencement of the Midwest ISO energy markets (April 1, 2005).¹⁹² Alliant committed "to refrain from making wholesale power sales at market-based rates under its market-based rate tariffs in the Alliant-East, Alliant-West, and Dairyland control areas prior to the commencement of the [MISO] energy markets."¹⁹³ "[D]uring the interim period prior to the start of the [MISO] markets, Alliant affiliates Wisconsin Power and Light Company (WPL) and Interstate Power and Light Company (IPL) [would] make wholesale power sales in the Alliant-East, Alliant-West and Dairyland control areas under cost-based wholesale power sales tariffs that WPL and IPL currently [had] on file at the Commission."¹⁹⁴

4. Cost Based Rates

Several entities have submitted cost based tariff proposals, which have been set for hearing,¹⁹⁵ or not yet addressed by the Commission.¹⁹⁶ The Commission, on September 19, 2005, conditionally accepted Aquila Inc.'s (Aquila's) cost-based rate proposal for filing.¹⁹⁷ Aquila "filed a proposal providing for cost-based rates applicable to sales of electric power at wholesale for transactions sinking in two Aquila control areas, . . . Missouri Public Service (Missouri) and West Plains Energy Kansas (Kansas), in order to mitigate the presumption of market power in those control areas."¹⁹⁸

The Commission noted that Aquila filed its cost-based rates as revisions to Aquila's market-based rate tariff; however, it believed that such cost-based rates

189. *Id.*

190. *Alliant Energy Corporate Servs., Inc.*, 112 F.E.R.C. ¶ 61,288 at P 1 (2005).

191. *Id.* at P 19.

192. 112 F.E.R.C. ¶ 61,288 at P 11.

193. *Id.*

194. 112 F.E.R.C. ¶ 61,288 at P 11.

195. *See, e.g., Duke Power*, 113 F.E.R.C. ¶ 61,192 (2005); *AEP Power Mktg. Inc.*, 114 F.E.R.C. ¶ 61,025 (2006).

196. *See, e.g., Entergy Servs., Inc.*, 111 F.E.R.C. ¶ 61,507 (2005).

197. *Aquila, Inc.*, 112 F.E.R.C. ¶ 61,307 at P 1 (2005).

198. *Id.*

are more appropriately included in a separate tariff.¹⁹⁹ The Commission directed Aquila to file “the cost-based rate provisions for sales into the Missouri and Kansas control areas as tariffs separate from the market-based rate tariffs, rather than including cost-based rates in the market-based rate tariffs.”²⁰⁰ Additionally, the Commission required cost support for these rates.

5. Change in Status Reporting under Order No. 652

In February 2005, the Commission issued Order No. 652, requiring each entity that is authorized to make sales at market-based rates (and all future applicants) to report any changes in status that could affect eligibility for market-based rate authority within thirty days after the change in status occurs, and incorporate this requirement into its market-based rate tariff.²⁰¹ The reporting obligations of Order No. 652 were effective on March 21, 2005. The rule eliminates the current option to delay reporting changes in status until submission of the triennial market-power review. The new rule does not affect the existing requirements that market-based sellers file triennial updates and quarterly reports.²⁰²

Order No. 652 requires public utilities with market-based rates to file a notice of change in status whenever there are changes within the utility’s control, in the facts on which the Commission relied in granting market-based rate authority under its current four-part test.²⁰³ That test examines whether the applicant or any affiliate is able to exercise generation market power, exercise transmission market power, raise barriers to entry, or engage in affiliate abuse or reciprocal dealing.²⁰⁴ The Order identifies certain events as changes in status that trigger the reporting obligation, if they are within the knowledge and control of the applicant and have not been disclosed in prior filings.²⁰⁵

Order No. 652 requires that change in status notices be filed within thirty days after the triggering event occurs.²⁰⁶ Such notices must include a transmittal letter including a description of the change in status and a narrative explaining whether (and if so, how) the change reflects a departure from the circumstances originally relied on by the Commission in the particular grant of market-based rate authority.²⁰⁷ Notices must indicate whether the reported change is material to market-based rate eligibility, and provide adequate support and analysis.²⁰⁸ Reports must be filed in the docket in which the market-based rate authority was granted and served on the service list for that docket. The Commission will then notice the filing and establish a comment period. Once noticed, the report has the legal effect of a compliance filing; therefore, the Commission is not required

199. 112 F.E.R.C. ¶ 61,307 at P 25.

200. *Id.*

201. Order No. 652, *Reporting Requirement for Changes in Status for Public Utilities with Market-Based Rate Authority*, F.E.R.C. STATS. & REGS. ¶ 31,175, 70 Fed. Reg. 8253 (2005) (to be codified at 18 C.F.R. pt. 35) [hereinafter Order No. 652], *order on reh’g*, 111 F.E.R.C. ¶ 61,413 (2005).

202. *Id.*

203. Order No. 652, *supra* note 201, at P 26.

204. *Id.* at P 7.

205. Order No. 652, *supra* note 201, at P 16.

206. *Id.*

207. Order No. 652, *supra* note 201, at P 84.

208. *Id.* at P 94.

to act on it within a set period of time.²⁰⁹ Given that this change in the status reporting requirement is a condition of obtaining and retaining market-based rate authority, sanctions for violations could include disgorgement of profits.

E. Resolution of 2000-01 Western Electricity Market Issues

1. *Proceedings Before the Federal Energy Regulatory Commission*

a. *California Refund Proceeding*

The California refund proceeding remains active, with no immediate end in sight. On August 8, 2005, the Commission issued an Order on Cost Recovery, Revising Procedural Schedule for Refunds, and Establishing Technical Conference (Cost Recovery Order).²¹⁰ The Commission issued this order to clarify the standards and procedures for sellers seeking to reduce their refund liability via a demonstration that the Commission's refund methodology would result in a total revenue shortfall for their transactions into the markets operated by the California Independent System Operator Corporation (CAISO) and California Power Exchange Corporation (Cal PX).²¹¹ Numerous sellers submitted cost recovery filings in response to the Cost Recovery Order, which filings remained pending before the Commission at the end of 2005. The Commission also addressed many procedural and technical issues in various orders throughout the year.

b. *Settlements*

Throughout the year, the Commission approved several new settlements resolving seller-specific issues in the California refund proceeding and related proceedings before the Commission.²¹² On April 13, 2005, the Commission approved a settlement with conditions that resolved issues concerning Mirant and several of the California public utilities and governmental entities, as well as the Commission's Office of Market Oversight and Investigations (OMOI).²¹³ On November 15, 2005, the Commission approved a settlement with conditions resolving many of the claims against Enron by the California entities, OMOI, and others;²¹⁴ the Commission also approved a settlement between Enron and the Salt River Project Agricultural Improvement and Power District (SRP) on November 30, 2005 (Enron-SRP Settlement).²¹⁵ On December 2, 2005, the Commission approved a settlement with conditions resolving claims against Public Service Company of Colorado.²¹⁶ With the exception of the Enron-SRP

209. Order No. 652, *supra* note 201.

210. *San Diego Gas & Elec. Co.*, 112 F.E.R.C. ¶ 61,176 (2005), *clarified*, 112 F.E.R.C. ¶ 61,249 (2005).

211. 112 F.E.R.C. ¶ 61,176 at P 1.

212. In addition, on May 9, 2005, the Commission issued an order on rehearing that generally affirmed, with clarifications, its prior orders approving settlements with Williams, Dynegy, and Duke. *San Diego Gas & Elec. Co.*, 111 F.E.R.C. ¶ 61,186 (2005).

213. *San Diego Gas & Elec. Co.*, 111 F.E.R.C. ¶ 61,017 (2005), *order on reh'g*, 111 F.E.R.C. ¶ 61,354 (2005).

214. *San Diego Gas & Elec. Co.*, 113 F.E.R.C. ¶ 61,171 (2005).

215. *San Diego Gas & Elec. Co.*, 113 F.E.R.C. ¶ 61,226 (2005). The Commission subsequently issued a corrected order on December 5, 2005. *San Diego Gas & Elec. Co.*, 113 F.E.R.C. ¶ 61,244 (2005).

216. *San Diego Gas & Elec. Co.*, 113 F.E.R.C. ¶ 61,235 (2005).

Settlement, these settlements provided other parties to the proceedings an opportunity to join the settlements and avoid the costs of litigation.

c. Show Cause Orders

On July 6, 2005, the Commission granted a motion to dismiss allegations of partnership gaming against Public Service Company of New Mexico.²¹⁷ As of December 31, 2005, virtually all entities named as respondents in the Commission's June 2003 Show Cause Orders, concerning alleged manipulation of the CAISO and Cal PX markets, had either been dismissed by the Commission or reached settlements with the Commission's Trial Staff that have been approved by the Commission.²¹⁸ Although many of the Commission's orders granting motions to dismiss and approving settlements remain subject to pending requests for rehearing, Enron remains the only party currently subject to the evidentiary hearing procedures established in the Show Cause Orders. The procedural schedule in the Enron proceeding has been suspended indefinitely to facilitate settlement discussions among the parties.²¹⁹

d. Report to Congress

Section 1824 of EPAct 2005 requires the Commission to seek to conclude its investigation of the California energy crisis as soon as possible, to ensure that refunds owed to California consumers are paid, and to submit to the United States Congress by December 31, 2005 a report describing actions taken and timetables for further action.²²⁰ On December 27, 2005, the Commission submitted a report describing its response to the California electricity crisis and addressing the anticipated timeline for distribution of refunds in the California refund proceeding (California Refund Report).²²¹ The Commission noted that its staff had facilitated settlements providing for over \$6.3 billion in refunds and other relief.²²² The Commission further explained that although it is committed to completing the California refund proceeding and providing for distribution of refunds as soon as possible, it must strictly adhere to due process principles and could not provide a definitive timeline for the distribution of refunds due to the multiplicity of issues yet pending before the Commission and the courts.²²³

2. Proceedings Before the United States Court of Appeals for the Ninth Circuit

a. Denial of Refund Authority Over Non-Public Utilities

On September 6, 2005, the Ninth Circuit granted petitions for review, filed by various non-public utilities, including governmental entities and an electric

217. *Pub. Serv. Co. of N.M.*, 112 F.E.R.C. ¶ 61,033 (2005).

218. *Am. Elec. Power Serv. Corp.*, 103 F.E.R.C. ¶ 61,345 (2003), *reh'g denied*, 106 F.E.R.C. ¶ 61,020 (2004); *Enron Power Mktg., Inc.*, 103 F.E.R.C. ¶ 61,346 (2003), *reh'g denied*, 106 F.E.R.C. ¶ 61,020 (2004).

219. *Enron Power Mktg., Inc.*, 113 F.E.R.C. ¶ 63,025 (2005).

220. Energy Policy Act of 2005, Pub. L. No. 109-58, § 1824, 119 Stat. 594.

221. FED. ENERGY REGULATORY COMM'N, THE COMMISSION'S RESPONSE TO THE CALIFORNIA ELECTRICITY CRISIS AND TIMELINE FOR DISTRIBUTION OF REFUNDS (2005) [hereinafter THE COMMISSION'S RESPONSE].

222. *Id.* at 14.

223. THE COMMISSION'S RESPONSE, *supra* note 221, at 20–26.

cooperative, of the Commission's orders holding that these entities were subject to refunds in the same manner as public utility sellers into the CAISO and Cal PX spot markets during the period covered by the California refund proceeding.²²⁴ In its orders in the California refund proceeding, the Commission acknowledged that the non-public utility sellers were not subject to its direct jurisdiction under section 206, but claimed authority to order those entities to pay refunds on the grounds that under the single price auction mechanism that operated in the CAISO and Cal PX spot markets, all sellers agreed to accept the same clearing price and that the market rules, which set the clearing prices, were subject to change if later found to be unjust and unreasonable.²²⁵

In response, the court concluded that the FPA unambiguously exempts governmental entities from the Commission's refund authority. The court noted that section 201(f) explicitly exempts governmental entities from the provisions of subchapter II of the FPA unless specifically stated in the relevant provision,²²⁶ that sections 205 and 206 explicitly apply only to public utilities, and that section 201(e) excludes governmental entities from the definition of "public utility."²²⁷ Furthermore, the court observed that the Commission's long-standing interpretation of sections 205 and 206 demonstrated its recognition that it lacked authority to order non-public utilities to pay refunds.²²⁸ The court also rejected the Commission's assertion that by participating in markets governed by Commission-approved tariffs and agreements, the non-public utilities had waived restrictions on the Commission's refund authority, noting that utilities cannot waive statutory authority or opt in or out of the Commission's jurisdiction.²²⁹ The court remanded the case for further proceedings, but on October 17, 2005 issued an order delaying issuance of the mandate and extending the time for seeking rehearing or rehearing en banc pending issuance of an order in a related appeal. These matters were still pending before the Ninth Circuit as of December 31, 2005.²³⁰

b. Preemption of State Law

On June 27, 2005, the United States Supreme Court denied a petition for writ of certiorari to the Ninth Circuit filed by Public Utility District No. 1 of Snohomish County, Washington (Snohomish).²³¹ Snohomish sought review of a Ninth Circuit decision affirming a district court's rejection of Snohomish's lawsuit against Dynegy and other sellers arising out of the California energy

224. *Bonneville Power Admin. v. FERC*, 422 F.3d 908 (9th Cir. 2005).

225. *San Diego Gas & Elec. Co.*, 96 F.E.R.C. ¶ 61,120, at p. 61,512 (2001), *order on reh'g*, 97 F.E.R.C. ¶ 61,275, at pp. 62,182–83 (2001).

226. *Bonneville*, 422 F.3d at 915.

227. *Id.* at 916–18. The court added that the Commission previously had ruled that Arizona Electric Power Cooperative, Inc. was not a public utility within the Commission's FPA jurisdiction, and that the Commission had offered no justification for treating it as one for purposes of refund liability in this instance. *Bonneville*, 422 F.3d at 917–18.

228. *Id.* at 921–22.

229. *Bonneville Power Admin. v. FERC*, 422 F.3d 908, 923–24 (9th Cir. 2005).

230. Also still pending before the Ninth Circuit as of December 31, 2005 are petitions for panel rehearing and rehearing *en banc* of *California ex rel. Lockyer v. FERC*, in which the court ruled that the Commission erred in concluding that it lacked authority to order refunds for violations of reporting requirements under the Commission's market-based sales regime. *California ex rel. Lockyer v. FERC*, 383 F.3d 1006 (9th Cir. 2004).

231. *Pub. Util. Dist. No. 1 v. Dynegy Power Mktg., Inc.*, 125 S. Ct. 2957 (2005).

crisis.²³² The Ninth Circuit held, consistent with other recent Ninth Circuit decisions,²³³ that the Commission has exclusive jurisdiction over interstate sales of electricity at wholesale, and therefore Snohomish's claims for treble damages under California antitrust and consumer protection statutes, and its claim for injunctive relief, were preempted.²³⁴

c. Port of Seattle, Washington (Port of Seattle) Challenge to the Enron Settlement

On December 12, 2005, the Ninth Circuit denied without comment two petitions for writs of mandamus filed by the Port of Seattle.²³⁵ The Port of Seattle, which has not reached a settlement with Enron and has requested rehearing of the Commission's order approving the Enron-California Settlement, sought an order staying the distribution of funds by the CAISO pursuant to the terms of that settlement, asserting that distribution of these amounts would deplete the funds available to Enron to pay potential liabilities arising out of the ongoing evidentiary hearing proceedings pursuant to the Show Cause Orders.²³⁶

F. Market Enforcement

1. EAct 2005 Provisions and the FERC's Implementation

Congress in EAct 2005 greatly expanded the FERC's authority to monitor electricity markets and to penalize market participants for market manipulation. Initially, in section 1281 of EAct 2005, Congress through the addition of section 220 to the FPA, directed that the Commission "facilitate price transparency in markets for the sale and transmission of electric energy in interstate commerce, having due regard for the public interest, the integrity of those markets, fair competition, and the protection of consumers."²³⁷ Congress contemplated that the FERC would achieve these purposes through the adoption of rules.²³⁸ However, Congress recognized that the disclosure of information in certain circumstances might have adverse consequences in the market, and allowed the Commission to exempt from disclosure "information the Commission determines would, if disclosed, be detrimental to the operation of an effective market or jeopardize system security."²³⁹ In this connection, new section 220 specifies that the "Commission shall seek to ensure that consumers and competitive markets are protected from the adverse effects of potential collusion or other anticompetitive behaviors that can be facilitated by untimely public disclosure of transaction-specific information."²⁴⁰

232. Pub. Util. Dist. No. 1 v. Dynegy Power Mktg., Inc., 384 F.3d 756 (9th Cir. 2005).

233. Pub. Util. Dist. No. 1 v. IDACORP, Inc., 379 F.3d 641 (9th Cir. 2004); *California ex rel. Lockyer v. Dynegy, Inc.*, 375 F.3d 831 (9th Cir. 2004).

234. *Dynegy Power Mktg., Inc.*, 384 F.3d at 760–62.

235. *Port of Seattle v. FERC*, Docket Nos. 05-76837, 05-76938 (9th Cir. Dec. 12, 2005).

236. See generally Request for Rehearing of the Port of Seattle, Washington, FERC Docket No. EL00-95-000 (Jan. 23, 2006).

237. Energy Policy Act of 2005, Pub. L. No. 109-58, § 1281, 119 Stat. 594.

238. *Id.*

239. Energy Policy Act of 2005 § 1281.

240. *Id.*

Relatedly, EPAct 2005 adds new section 221 to the FPA that prohibits the reporting of any information known to be false "relating to the price of electricity sold at wholesale or the availability of transmission capacity" to any Federal agency.²⁴¹ To violate this prohibition, such reporting must have been done with the "intent to fraudulently affect the data being compiled by the Federal agency."²⁴²

EPAct 2005 added new section 222 to the FPA, which makes it unlawful for any entity, in contravention of rules to be adopted by the Commission, "directly or indirectly, to use or employ, in connection with the purchase or sale of electric energy or the purchase or sale of transmission services subject to the jurisdiction of the Commission, any manipulative or deceptive device or contrivance"²⁴³ As used in this section, the terms "manipulative or deceptive device or contrivance" are to be the same as those used in section 10(b) of the Securities Exchange Act of 1934.²⁴⁴ However, section 222 is express in not creating a private right of action.

Finally, to give effect to these and the other provisions of the FPA, EPAct 2005 sections 1284(d) and 1284(e) revises existing section 316 of the FPA by increasing the Commission's civil authority from \$10,000 to \$1,000,000 for each day that a violation continues, increases criminal penalties by raising the maximum monetary fine from \$5,000 to \$1,000,000, and raising the maximum criminal sentence from two to five years.²⁴⁵ Moreover, it removed the previous limitation on the FERC's penalty authority, which made such penalties applicable only to violations of the FPA sections providing for mandatory wheeling and interconnections, so that such penalties may now apply to any violation of part II of the FPA.²⁴⁶

On October 20, 2005, the Commission issued a Policy Statement on Enforcement to provide the industry with guidance regarding the factors that it would consider in determining remedies for violations under the FPA and the other statutes it administers.²⁴⁷ Although not limited to the provisions of the FPA adopted by EPAct 2005, the impetus for the issuance of the Policy Statement is the Commission's enhanced civil penalty authority under EPAct 2005. In fashioning this policy, the Commission took into account the policies of other governmental agencies. Indicating that its enhanced penalty authority under EPAct 2005 would operate in tandem with its existing authority to require the disgorgement of unjust profits obtained through misconduct and to impose other penalties, such as the loss of market-based rate authority, the Commission set out various factors that it would take into account in assessing penalties.²⁴⁸ Specifically, the Commission indicated that it would evaluate the seriousness of a violation by assessing a number of factors, including harm, whether the violation was the result of manipulation, whether it was willful, whether it was an isolated event or whether there was a history of similar violations, and what

241. Energy Policy Act of 2005 § 1282.

242. *Id.*

243. Energy Policy Act of 2005, Pub. L. No. 109-58, § 1283, 119 Stat. 594.

244. *Id.*

245. Energy Policy Act of 2005 § 1284.

246. *Id.*

247. *Enforcement of Statutes, Orders, Rules, and Regulations*, 113 F.E.R.C. ¶ 61,068 at P 5 (2005).

248. *Id.* at P 12.

role executive management played in the violation.²⁴⁹ It also indicated that it would take into account whether the entity had an effective internal compliance program, whether it self-reported the violation, and whether it cooperated with the Commission, all factors that could in certain circumstances mitigate against the severity of a penalty.²⁵⁰ Concurrently with the Policy Statement, the Commission issued a NOPR setting forth proposed rules to implement FPA section 222. In this NOPR, the Commission proposed adding new regulations that would make it unlawful for any entity, not just jurisdictional utilities, directly or indirectly in connection with the purchase or sale of electric energy or the purchase or sale of transmission services subject to FERC's jurisdiction,

(1) to use or employ any device, scheme, or artifice to defraud, (2) to make any untrue statement of a material fact or to omit to state a material fact necessary in order to make the statements made, in the light of the circumstances under which they were made, not misleading, or (3) to engage in any act, practice, or course of business that operates or would operate as a fraud or deceit upon any person.²⁵¹

The Commission modeled its proposed regulations on the Security and Exchange Commission's Rule 10b-5.²⁵² The Commission indicated that this approach was consistent with the Congressional mandate "that the Commission's new authority be exercised in a manner consistent with section 10(b) of the Exchange Act"²⁵³ The Commission further stated that "[t]his approach should provide benefits to entities subject to the new rule because there is a substantial body of precedent applying the comparable language of Rule 10b-5."²⁵⁴

In proposing its new market manipulation rule, the Commission recognized that there was some overlap between this rule and its Market Behavior Rules, the rules that the Commission has required be included in all market-based rate tariffs to prevent market manipulation.²⁵⁵ Consistent with this concern, the Commission a month later issued an order in which it proposed to eliminate its existing Market Behavior Rules upon the implementation of its proposed market manipulation rule. Although requesting comment on its proposal, the Commission analyzed the requirements of its existing Market Behavior Rules and explained that the requirements either duplicated other existing rules or would cover situations adequately covered by the proposed market manipulation rule. In this context, the Commission viewed repeal of the Market Behavior Rules as a simplification of its existing rules and regulations that would "streamline the rules and regulations sellers must follow," and not "eliminate beneficial rules governing market behavior."²⁵⁶

249. 113 F.E.R.C. ¶ 61,068 at P 20.

250. *Id.* at P 22.

251. Notice of Proposed Rulemaking, *Prohibition of Energy Market Manipulation*, F.E.R.C. STATS. & REGS. ¶ 32,591 at P 8, 70 Fed. Reg. 61,930 (2005) [hereinafter *Prohibition of EMM*].

252. 17 C.F.R. § 240.10b-5 (2005).

253. *Prohibition of EMM*, *supra* note 251, at P 2.

254. *Id.*

255. *Investigation of Terms and Conditions of Public Utility Market-Based Rate Authorizations*, 105 F.E.R.C. ¶ 61,218 at PP 1-2 (2003), *reh'g denied*, 107 F.E.R.C. ¶ 61,175 (2004).

256. *Investigation of Terms and Conditions of Public Utility Market-Based Rate Authorizations*, 113 F.E.R.C. ¶ 61,190 at P 13 (2005).

2. OMOI Activities

From an enforcement standpoint, 2005 was also notable because of the stepped up level of activity by FERC's OMOI. OMOI conducted a number of routine operational audits of a number of jurisdictional entities to test compliance with various FERC requirements, including open-access transmission tariff requirements, the requirements of FERC's standards of conduct governing the interrelationship of a utility's transmission and merchant functions, and requirements relating to affiliate transactions.²⁵⁷ OMOI issued several audit reports, all of which found some level of noncompliance ranging from minor to significant on the part of the audited entities. All of the issued reports included agreed-to compliance programs, with some entities agreeing to compliance corrections that required substantial monetary expenditures.²⁵⁸

G. Corporate and Affiliate

1. EPOA 2005 Repeal of PUHCA and the FERC's Implementation

The Energy Policy Act enacted a new law, the Public Utility Holding Company Act of 2005 (PUHCA 2005), which, among other things, repeals the Public Utility Holding Company Act of 1935 (PUHCA), effective February 8, 2006.²⁵⁹

The repeal of PUHCA removes certain geographic and business restrictions imposed on holding companies.²⁶⁰ Entities no longer must obtain Securities and Exchange Commission (SEC) approval for acquisitions of new utility assets and utility mergers as well as routine operational matters, such as financing and intercompany service agreements. The repeal of PUHCA does away with restrictions on the types of investments that holding companies can make, and eliminates constraints on companies in other businesses acquiring utilities and holding companies.²⁶¹

Under PUHCA 2005, the FERC is authorized to impose certain recordkeeping and reporting requirements on holding companies previously imposed by the SEC. Generally, each utility holding company and its affiliates must provide to the FERC such books and records that the FERC determines are relevant to costs incurred by a natural gas company or an electric public utility within such holding-company system and necessary or appropriate for the protection of utility customers with respect to FERC jurisdictional rates.²⁶²

On December 8, 2005, the FERC issued Order No. 667,²⁶³ its final rule to implement the PUHCA 2005. Among other things, the FERC determined that it would not continue the distinction between "exempt" and "registered" holding companies, finding that:

257. *MidAmerican Energy Co.*, 112 F.E.R.C. ¶ 61,346 (2005).

258. *Id.* at P 8 (2005) (citing the Order approving audit report and directing compliance actions requiring MidAmerican to construct \$9.2 million of previously unplanned transmission upgrades).

259. Energy Policy Act of 2005, Pub. L. No. 109-58, §§ 1263, 1274, 119 Stat. 594.

260. *Id.* §§ 1261-1277.

261. Energy Policy Act of 2005 §§ 1261-1277.

262. *Id.* § 1264.

263. Order No. 667, *Repeal of the Public Utility Holding Company Act of 1935 and Enactment of the Public Utility Holding Company Act of 2005*, F.E.R.C. STATS. & REGS. ¶ 31,197, 70 Fed. Reg. 75,592 (2005) (to be codified at 18 C.F.R. pts. 365, 366) [hereinafter Order No. 667].

there is no basis in PUHCA 2005 for distinguishing between holding companies based on their registered or exempt status under PUHCA 1935. Accordingly, the Commission will subject all holding company systems, whether previously exempt or registered, to the books and records requirements that PUHCA 2005 imposes on holding companies and affiliates, associate companies, and subsidiaries thereof, unless they qualify for one of the statutory exemptions provided for under section 1266 of PUHCA 2005.²⁶⁴

The Commission also eliminated its exempt wholesale generator (EWG) rules, and in their place established the processes by which new wholesale power suppliers can obtain EWG or FUCO status through requests for declaratory orders or self-certification.²⁶⁵

In addition, PUHCA 2005 also does the following: subject to certain safeguards, grants state regulatory commissions access to books and records of a holding company and its affiliates if the state commission determines that such books and records are relevant to costs incurred by an electric or gas distribution utility it regulates and access is necessary to enable the state agency to effectively discharge its duties;²⁶⁶ provides that nothing in the new act affects FERC's authority to require just and reasonable rates, including the ability to deny or approve cost pass-throughs and prevent cross-subsidization between a utility and an affiliate; makes clear that FERC shall have the same power as set forth in sections 306 through 317 of the FPA to enforce the provisions of PUHCA 2005;²⁶⁷ and authorizes FERC, at the election of a holding company system or applicable state commission, to review and authorize the allocation of costs for non-power goods or administrative or management services provided by a service company to a public utility company in the same holding company system.²⁶⁸

2. Interlocking Directors

On September 16, 2005, the Commission issued Order No. 664,²⁶⁹ a final order amending and clarifying part 45²⁷⁰ of its regulations concerning interlocking directorates.²⁷¹ Specifically, the Commission clarified section 45.3

264. *Id.* at P 37 (footnote omitted). Section 1266 requires that the Commission exempt wholesale generators (EWGs), foreign utility companies (FUCOs), and qualifying facilities (QFs), as well as a person or transaction where the FERC finds that such books and records are not relevant to FERC-jurisdictional rates. Order No. 667, *supra* note 263, at PP 34–38.

265. *Id.* at PP 226–29.

266. Energy Policy Act of 2005, Pub. L. No. 109-58, § 1265, 119 Stat. 594.

267. *Id.* § 1270.

268. Energy Policy Act of 2005 § 1275. In Order No. 667, the Commission determined that:

we will not require the formal filing of cost allocation agreements and . . . we will not require any entities that are currently using the SEC's "at-cost" standard for traditional centralized service companies to switch to our "market" standard. With respect to traditional, centralized service companies that use the "at cost" standard, we will apply a presumption that "at cost" pricing of the non-power goods and services they provide to public utilities within their holding company system is reasonable, but persons may file complaints if they believe that use of at cost pricing results in costs that are above market price. We will also retain the Commission's existing "market" standard for non-power goods or services transactions between special-purpose subsidiaries and public utilities.

Order No. 667, *supra* note 263, at P 14.

269. Order No. 664, *Commission Authorization to Hold Interlocking Positions*, F.E.R.C. STATS. & REGS. ¶ 31,194, 70 Fed. Reg. 55,717 (2005) (to be codified at 18 C.F.R. pt. 45) [hereinafter Order No. 664].

270. 18 C.F.R. pt. 45 (2005).

271. The Commission's responsibility concerning interlocking positions is set out in section 305(b) of the

of its regulations to make clear that an application to hold interlocking positions must be filed and authorized prior to the applicant assuming the otherwise prohibited interlocking position.²⁷² Previously, the regulations allowed an applicant to file for Commission authorization up to thirty days after being appointed to the interlocking position.²⁷³ The Commission also declined a request by the MISO that the regulations' scope be expanded to include directors of non-jurisdictional utilities seeking to serve on RTOs or ISOs because it found that FPA section 305(b) only addresses public utilities.²⁷⁴ And, in keeping with the tough tone of the order, the Commission determined that late-filed applications automatically will be denied.²⁷⁵

The final rule also clarified section 45.9 concerning automatic authorization for some interlocking positions, holding that the required informational report be filed before assuming the interlocking position, and further, that such a report must state or affirm that the person seeking the automatic authorization has not begun to fill the interlocking position.²⁷⁶ Finally, the Commission also ruled that it would no longer grant a waiver of the full requirements of part 45 in orders granting market-based rate authority.²⁷⁷

H. Mergers and Acquisitions

The Commission issued several dozen orders addressing section 203 applications in 2005. This section summarizes some of the major orders the Commission issued. In addition, pursuant to EAct 2005 the Commission revised its regulations for processing applications under section 203 of the FPA. This section summarizes those new regulations.

Federal Power Act, 16 U.S.C. § 825d(b) (2000), which states in part that:

it shall be unlawful for any person to hold the position of officer or director of more than one public utility or to hold the position of officer or director of a public utility and the position of officer or director of any bank, trust company, banking association, or firm that is authorized by law to underwrite or participate in the marketing of securities of a public utility, or officer or director of any company supplying electrical equipment to such public utility, unless the holding of such positions shall have been authorized by order of the Commission, upon due showing in form and manner prescribed by the Commission, that neither public nor private interests will be adversely affected thereby.

Federal Power Act § 305(b); 16 U.S.C. § 825d(b)(1) (2000). Section 305(b)(2) provides an exception for officers or directors of banks, underwriters, and securities marketers.

272. Order No. 664, *supra* note 269, at PP 15–19.

273. *Id.* at P 18. The Edison Electric Institute had argued in comments that prior authorization was unnecessary and burdensome, and that the thirty-day post-appointment window for seeking Commission authorization should actually be expanded to sixty days. The Commission strongly rejected this argument, stating that “[t]he statute speaks of *prior* authorization and that is what the regulations should require; *prior* authorization, not 30 days and not 60 days after the fact.” Order No. 664, *supra* note 269, at P 18 (emphasis in original).

274. *Id.* at P 19.

275. Order No. 664, *supra* note 269, at P 30.

276. Automatic authorization is permitted only where the interlocking positions are between two or more public utilities.

277. Order No. 664, *supra* note 269, at P 35.

1. Transactions

a. Exelon Corp. and Public Service Enterprise Corp.

In *Exelon Corp. and Public Service Enterprise Corp.*, the Commission authorized the merger of Exelon Corp. and Public Service Enterprise Group Inc. to create Exelon Electric & Gas Corp.²⁷⁸ The Commission approved the merger over numerous objections after finding that the applicants' proposed mitigation measures would adequately address the effects of the transaction on the market. However, because the applicants' mitigation required the implementation of future changes, the Commission required the applicants to submit updated market power analyses after those changes occur to verify that they have the effect of mitigating market power.²⁷⁹

In light of the size of the applicants, the Commission's assessment of horizontal market power issues in this proceeding, including applicants' mitigation proposal, is particularly noteworthy. To mitigate the effects of the transaction, the applicants proposed a mitigation plan that included the divestiture of 2,900 MW of generation capacity (but not specified units) in PJM-East, consisting of 1,000 MW of peaking generation and 1,900 MW of mid-merit generation, of which at least 550 MW was coal-fired capacity (with restrictions on who could buy the capacity); an interim mitigation plan to be in place at the time of merger consummation (proposed because the Commission requires that mitigation be in place at the time of closing); and a "virtual divestiture" to address the Appendix A screen failures for the off-peak periods, pursuant to which applicants proposed to sell long-term energy rights from nuclear baseload units.²⁸⁰

In assessing horizontal market power, the Commission found that "PJM-Classic" need not be studied as a separate relevant geographic market within PJM Pre-2004.²⁸¹ The FERC based its finding on the fact that the PJM market monitoring unit report did not consider PJM-Classic as a separate market, and no party demonstrated that there are frequent binding transmission constraints that isolate PJM-Classic from the rest of PJM Pre-2004.²⁸² The Commission also rejected arguments that PJM-West should be considered a separate geographic market. The Commission explained that the "critical issue in defining geographic markets is identifying the sellers who can physically and economically compete in the market."²⁸³ The FERC found that, "[g]iven that the binding transmission constraints within PJM are predominantly west-to-east, it is reasonable to model PJM-East as a separate market within PJM, but not necessary to model PJM-West as a separate market because suppliers from all of PJM are able to sell into PJM-West."²⁸⁴ However, the FERC did find that "Northern New Jersey" was a relevant geographic market because there were times when transmission constraints bind and thereby isolate, Northern New

278. *Exelon Corp.*, 112 F.E.R.C. ¶ 61,011 (2005), *order denying reh'g*, 113 F.E.R.C. ¶ 61,299 (2005).

279. *Id.*

280. 112 F.E.R.C. ¶ 61,011 at PP 25–27.

281. *Id.* at P 123.

282. 112 F.E.R.C. ¶ 61,011 at P 123.

283. *Id.* at P 124.

284. *Exelon Corp.*, 112 F.E.R.C. ¶ 61,011 at P 124 (2005).

Jersey from the rest of PJM-East.²⁸⁵ Moreover, the Commission agreed with the applicants that, during those periods, the merger would not harm competition because Exelon does not have any generating facilities that would be combined with PSE&G's existing generation in that load pocket. Nonetheless, based on the applicants' commitment to mitigate all screen failures and the applicants' finding that a 100 MW divestiture of generation capacity located in Northern PSE&G, along with the proposed mitigation for the PJM East market, is necessary to fully mitigate the merger-related increase in market concentration in Northern PSE&G, the Commission required the applicants to divest 100 MW of generation located within Northern PSE&G.²⁸⁶

The Commission found that "the effectiveness of Applicants' proposed divestiture [would] depend[] on the distribution of the buyers and their pre-existing presence as sellers in the PJM markets."²⁸⁷ The

applicants initially addressed this issue by putting restrictions on the pool of eligible buyers and the amount of the divested capacity that any one purchaser can acquire. However, many protestors argued that such restrictions could harm the competitive process and could even allow Applicants to gain a dominant position in PJM by having only smaller, weaker competitors.²⁸⁸

Therefore, in addition to subjecting each individual divestiture to section 203 review, the Commission held that at the end of the divestiture process, applicants must submit a compliance filing to show that market concentration in the affected markets is close to pre-merger levels.²⁸⁹ The FERC concluded that "[i]f the analysis shows that the merger's harm to competition has not been sufficiently mitigated, it will require additional mitigation at that time."²⁹⁰

The Commission denied requests that it analyze the merger's effect on the applicants' ability and incentive to harm competition by engaging in strategic bidding.²⁹¹ The Commission also rejected assertions that the applicants' proposed virtual divestiture of energy from nuclear capacity was inadequate because it failed to transfer operational control to the buyers.²⁹² The Commission concluded that the virtual divestiture is, in effect, a must-offer provision that removes the ability to withhold output from the market.²⁹³

A number of protestors argued that the Commission's Merger Policy Statement requires applicants to identify the specific units that will be divested. In response, the Commission found the applicants' proposal to be sufficient because once the specific units have been identified, the Commission will be able to ensure that they are appropriate units to make divestiture effective through the compliance filing.²⁹⁴

The Commission ruled that the amount of interim mitigation, "along with applicants' variable cost bid caps for the mid-merit and peaking units, mitigates

285. *Id.* at P 122.

286. 112 F.E.R.C. ¶ 61,011 at P 122.

287. *Id.* at P 127.

288. 112 F.E.R.C. ¶ 61,011 at P 123.

289. *Id.* at P 128.

290. *Exelon Corp.*, 112 F.E.R.C. ¶ 61,011 at P 178 (2005).

291. *Id.* at P 131.

292. 112 F.E.R.C. ¶ 61,011 at P 48.

293. *Id.* at P 134.

294. 112 F.E.R.C. ¶ 61,011 at P 141.

the merger-related harm to competition in the relevant energy markets.”²⁹⁵ The Commission acknowledged that the applicants would offer the same amount of capacity in their interim mitigation as in their proposed physical and virtual divestiture, which was found to adequately mitigate the merger-related harm to competition. The Commission also concluded that “the commitment to bid the fossil units at variable cost eliminates the ability to harm competition by strategic bidding or economic withholding.”²⁹⁶ However, the Commission relied on the “[a]pplicants’ commitment to establish a public compliance web site [to show] how they are complying with the virtual divestiture and all other mitigation requirements, including the interim mitigation plan, and require[d] that the interim mitigation be in place upon consummation of the merger.”²⁹⁷

The Commission also addressed applicants’ transmission commitments. The Commission indicated that it was not relying on those commitments in “finding that applicants’ proposed mitigation adequately addresses the merger-related harm to competition.”²⁹⁸ Instead, the Commission relied on the applicants’ proposed sale of capacity. Further, the Commission ruled that it “will allow offsets to the baseload mitigation amount specifically for transmission expansions that increase import capability into PJM-East.”²⁹⁹

In addition to the physical divestiture of generating capacity, applicants committed to bid all of their uncommitted capacity at zero. The Commission concluded that, under this proposal, the applicants will have no ability to withhold capacity to increase the market clearing price.³⁰⁰ However, the Commission was concerned that the mitigation might not be sufficient in capacity market structures that PJM may adopt in the future. Therefore, the Commission held that, when it approves a new capacity market for PJM, the applicants must submit a new analysis of the merger’s effect on the PJM capacity market and, “if the analysis shows that the merger-related harm to competition is not fully mitigated, propose a new mitigation plan for the Commission’s approval within 30 days of any such approvals.”³⁰¹

The Commission also addressed whether the proposed merger would harm competition in PJM’s ancillary services markets, and concluded that it would not.³⁰²

b. Duke Energy Corp. and Cinergy Corp.

In *Duke Energy Corp. and Cinergy Corp.*, the Commission approved the merger of Duke and Cinergy to form “an entity with retail electric and gas customers in Ohio, Kentucky, Indiana, North Carolina, South Carolina, and Canada, and that will own over 45,000 MW of electric generation and 17,500 miles of natural gas transmission pipeline.”³⁰³

Largely due to the fact that the Duke and Cinergy markets do not overlap,

295. *Id.* at P 144.

296. *Exelon Corp.*, 112 F.E.R.C. ¶ 61,011 at P 144 (2005).

297. *Id.* at P 144.

298. 112 F.E.R.C. ¶ 61,011 at P 147.

299. *Id.* at P 147.

300. 112 F.E.R.C. ¶ 61,011 at P 157.

301. *Id.* at P 167.

302. *Exelon Corp.*, 112 F.E.R.C. ¶ 61,011 at P 178 (2005).

303. *Duke Energy Corp.*, 113 F.E.R.C. ¶ 61,297 (2005).

the Commission concluded "that the horizontal aspects of the merger will not harm competition in any relevant market."³⁰⁴ The Commission noted that "[t]he MISO market, where Cinergy's capacity is located, is not concentrated, and the combination of Cinergy's generation and Duke's generation that could reach the MISO passes the Competitive Analysis Screen for all season/load levels."³⁰⁵ The Commission also found that, although "[t]he Duke market is highly concentrated, with Duke being the dominant firm in that market, . . . the proposed merger did not eliminate a competitor in that market" because Cinergy does not have any significant presence in the Duke market.³⁰⁶ The Commission explained that, even if it accepted protestors' revisions to the applicants' analysis, which would show screen failures in the Duke market by allowing more of Cinergy's generation to reach the Duke destination market, the fundamental competitive conditions in the market would not be changed by the proposed merger.³⁰⁷ Further, the Commission added that in *Northern States Power Company*, the Commission already determined that it has little concern over screen failures caused by factors other than the elimination of a competitor.³⁰⁸

In approving this merger, the Commission also addressed and rejected certain novel market power claims. Specifically, one intervenor argued "that the combination of assets on either side of a major entry point to the proposed MISO-PJM joint energy market will give Duke opportunities to affect regional prices."³⁰⁹ The Commission rejected the argument. After analyzing several permutations of how a seller on one side of the MISO-PJM interface could seek to impact the price of power on the other side of the interface, the Commission concluded that the withholding strategy would be "exceedingly problematic" and would not pose a significant threat to competition.³¹⁰ The Commission also rejected assertions that the Commission review the Duke/Cinergy merger in a special light as a "harbinger of change" in the industry. The Commission held that, under section 203 of the FPA, the Commission reviews the transaction before them to determine whether it is consistent with the public interest and the Commission "[c]annot deny or condition a proposed merger based on speculation about general trends that may or may not occur in the future."³¹¹ The Commission rejected the argument that it should review the transaction under the "potential competition" theory.³¹² The Commission found that the acquiring firm's pre-merger presence on the fringe of the target market could not possibly have tempered oligopolistic behavior on the part of existing participants in the

304. *Id.* at P 83.

305. 113 F.E.R.C. ¶ 61,297 at P 83.

306. *Id.*

307. 113 F.E.R.C. ¶ 61,297 at P 81.

308. *Id.* at P 83 (referencing *Northern States Power Company*, 90 F.E.R.C. ¶ 61,020 (2000)).

309. *Duke Energy Corp.*, 113 F.E.R.C. ¶ 61,297 at P 74 (2005).

310. *Id.* at PP 75-77.

311. 113 F.E.R.C. ¶ 61,297 at P 78.

312. *Id.* The intervenor cited *United States v. Marine Bancorporation, Inc.*, 418 U.S. 602 (1974). The intervenor indicated that, under the "potential competition" theory,

a merger may be unlawful if: the target . . . is substantially concentrated; the acquiring firm has the characteristics, capabilit[y] and economic incentive to render it a perceived potential de novo entrant; and the acquiring firm's pre-merger presence on the fringe of the target market (as a potential entrant) in fact tempered oligopolistic behavior on the part of existing participants in the market.

113 F.E.R.C. ¶ 61,297 at P 40.

market under the circumstances.³¹³ The Commission concluded that the record did not show that the Duke Power control area is an oligopolistic market. Moreover, given Cinergy's lack of physical proximity to Duke and the lack of historical sales in the market, the record did not contain any evidence to show that Cinergy was perceived as a potential competitor in the Duke control area.³¹⁴

With respect to the issue of vertical market power, The Commission held that the combination of the applicants' generation and transmission facilities will not harm competition. The Commission found that the applicants' transmission systems are generally remote from each other's generation, so there is no incentive or ability to exercise vertical market power.³¹⁵ The Commission ruled that, because "Cinergy . . . turned over operational control of its transmission facilities to the MISO, . . . it cannot use its transmission assets to harm competition in downstream electricity markets."³¹⁶ "In addition, because Duke Power's transmission system is far removed from Cinergy's generation assets, which are in MISO, it would not be able to use control of its transmission assets to harm competition in the relevant downstream electricity markets."³¹⁷

With respect to the effect of the proposed merger on regulation, the Indiana Commission raised concerns "that the merger will create a multi-state holding company covering some states where rates are set by competitive forces and other states where they are set by cost-based regulation."³¹⁸ The Commission rejected the argument and stated that PUHCA 2005 is not intended to prevent any state commission from exercising its jurisdiction under otherwise applicable law to protect utility customers. Further, the Commission concluded that the "Indiana Commission retains jurisdiction over the affiliate transactions with which it is concerned."³¹⁹ Thus, the Commission rejected requests by the Indiana Commission to "place the proceeding on a settlement track and [to] condition [the] . . . approval of the merger on state regulators retaining their authority regarding mergers that affect rates paid by retail ratepayers."³²⁰

c. MidAmerican Energy Holdings Co., Scottish Power plc, et al.

In *MidAmerican Energy Holdings Co.*, (*MidAmerican*), the Commission approved the sale of PacifiCorp to a wholly-owned subsidiary of MidAmerican Holdings.³²¹ The applicants submitted their application prior to the passage of EPAct 2005 and, as a result, initially proposed to obtain a fifty MW transmission path between the applicants' facilities so as to operate on an integrated basis, as required by PUHCA. Applicants later amended their application to eliminate the proposed transmission path due to the repeal of PUHCA 1935.³²²

Applicants asserted that, with the elimination of the fifty MW transmission path, there were no screen failures in any time period and no merger-related

313. 113 F.E.R.C. ¶ 61,297 at P 40.

314. *Duke Energy Corp.*, 113 F.E.R.C. ¶ 61,297 at P 79 (2005).

315. *Id.* at P 79.

316. 113 F.E.R.C. ¶ 61,297 at P 99.

317. *Id.* at P 132.

318. 113 F.E.R.C. ¶ 61,297 at P 127.

319. *Id.* at P 132.

320. *Duke Energy Corp.*, 113 F.E.R.C. ¶ 61,297 at P 132 (2005).

321. *MidAmerican Energy Holdings Co.*, 113 F.E.R.C. ¶ 61,298 (2005).

322. *Id.*

changes in HHI greater than one point, which the applicants indicated was actually deconcentrating.³²³ Thus, the applicants asserted that the effect of the merger on this market is *de minimis*. The Commission agreed.³²⁴

The Commission rejected arguments that the applicants failed to address all markets. The Commission noted that the applicants argued that, "because the effect of the transaction on PacifiCorp West and MidAmerican is *de minimis*, the effect on their first tier markets is necessarily *de minimis* because MidAmerican and PacifiCorp control very little capacity outside of their respective control areas."³²⁵ The Commission "agreed with the argument because there are no remote markets where both MidAmerican and PacifiCorp own significant generation capacity."³²⁶

The Commission also rejected arguments that, due to the pending repeal of PUHCA and the anticipation of more "cross-country" mergers, it should analyze more than the effects of this merger on competition.³²⁷ The Commission made clear that it will not use a specific application to address issues that may be raised in future mergers.³²⁸ The Commission stated that, although its standard of review is flexible enough to consider any changes in market structure that ultimately result from the EPA and the repeal of PUHCA, the Commission will not speculate on what general trends might emerge and "will evaluate the effect of this merger on competition based on the record in each case."³²⁹

The applicants explained that none of the MidAmerican generation assets are located on the PacifiCorp system and none of the PacifiCorp generation assets are located on the MidAmerican system.³³⁰ Thus, the applicants asserted that the transaction did not raise any vertical market power issues. The Commission agreed. Further, the Commission noted that no party challenged the applicants' assertion that the merger raised no vertical market power issues.³³¹

The applicants committed to "hold transmission customers harmless from any increase in transmission rates to the extent that transaction-related costs exceed demonstrated transaction-related savings."³³² In addition, applicants explained that the rates of wholesale power requirements customers and customers paying fixed rates would not be adversely affected. The Commission found that the applicants demonstrated that the transaction would not adversely affect transmission rates or wholesale power rates.³³³ The Commission relied on the applicants' hold harmless commitment in making its finding. An intervenor complained that the merged company's post-transaction operations may result in new power flows that may cause transmission constraints.³³⁴ In response, the applicants stated that they would keep their systems separate and that there are

323. 113 F.E.R.C. ¶ 61,298 at P 21.

324. *Id.* at P 30.

325. 113 F.E.R.C. ¶ 61,298 at P 31.

326. *Id.* at P 31.

327. *MidAmerican Energy Holdings Co.*, 113 F.E.R.C. ¶ 61,298 at P 26 (2005).

328. *Id.* at P 32.

329. 113 F.E.R.C. ¶ 61,298 at P 32.

330. *Id.* at P 34.

331. 113 F.E.R.C. ¶ 61,298 at P 37.

332. *Id.* at P 40.

333. *MidAmerican Energy Holdings Co.*, 113 F.E.R.C. ¶ 61,298 at P 45 (2005).

334. *Id.* at P 45.

no plans for a joint operating agreement at this time. The Commission added, however, that if the applicants file a joint operating agreement at a later date, the intervenor could raise its concerns then.³³⁵

d. La Paloma Holding Co., LLC; Lake Road Holding Co. LLC

In *La Paloma Holding Co., LLC*, and *Lake Road Holding Co., LLC*,³³⁶ the Commission authorized the future transfer of equity interests to undetermined buyers under certain conditions.³³⁷

The applicants sought authorization for a two-year period to make transfers of equity interests to other existing owners or new buyers, which are financial institutions that are not primarily engaged in energy related activities, subject to a limitation of 20% interest for any holder.³³⁸ In *Lake Road*, the Commission indicated that it did not want to leave to the applicant the role of determining whether an entity was primarily engaged in energy related activities. Therefore, the Commission added the condition that any buyer and its affiliates could “not collectively own or control [5%] or more voting interest in any public utility that has interests in any generation facilities or engages in jurisdictional activities” within the market in which the underlying generation facility was operated.³³⁹ Thus, for Lake Road, the buyer could not collectively own or control 5% or more voting interest in any public utility that has interests in any generation facilities or engages in jurisdictional activities within New England ISO. For La Paloma, the limit applied to the market operated by the California ISO. In addition, the Commission required that any transferor of interests will be reported within ten days and will include a statement of other generating or power marketing interests directly or indirectly owned by the buyer or its affiliates regardless of the market or region in the country in which such interests are operated.³⁴⁰

Further, the Commission required that, within thirty days of the closing of the initial sale transaction, and in any subsequent notification of holding company equity sales transactions, the applicants submit following information:

- the identity of both pre-and post-transaction equity holders (and percentage ownership) of the holding company . . . ;
- any contracts for (or a summary thereof) power purchase agreements, energy management services, asset management services, and any fuel supply services provided to the facility, each of which should identify the contract counterparty, and any affiliation between that counterparty and post-transaction equity holders; and
- the identify of any parties acquiring equity interests that are subject to the Commission’s Code of Conduct rules as a result of acquiring the equity interests.³⁴¹

Further, the Commission indicated that the filing “requirements do not relieve the buyer or its affiliates from complying with the Commission’s other

335. 113 F.E.R.C. ¶ 61,298 at P 45.

336. *Lake Road Holding Co.*, 112 F.E.R.C. ¶ 61,051 (2005).

337. *La Paloma Holding Co.*, 112 F.E.R.C. ¶ 61,052 (2005).

338. 112 F.E.R.C. ¶ 61,052 at P 6; 112 F.E.R.C. ¶ 61,051 at P 6.

339. 112 F.E.R.C. ¶ 61,051 at P 16.

340. 112 F.E.R.C. ¶ 61,052 at P 18.

341. *Id.* at PP 18–19.

reporting requirements,” including the need to notify the Commission of change in status under a market-based rate tariff or quarterly reports.³⁴²

e. Nevada Power Co. and Gen West, LLC

In *Nevada Power Co. and Gen West, LLC* (*Nevada Power*), the Commission agreed that Available Economic Capacity (AEC) is the “more relevant” measure of market power for a utility that has dedicated its generation resources to serve native load.³⁴³ Under its regulations, the Commission requires an applicant to evaluate its market power by analyzing both Economic Capacity, which does not take into account the applicant’s pre-existing obligations, and AEC, which recognizes that the applicant’s resources may be dedicated to serve others.³⁴⁴

Because the AEC analysis takes into account the applicant’s other obligations, an applicant’s market share under AEC is generally lower than when considering Economic Capacity. Thus, in section 203 proceedings applicants generally argue that the more accurate measure of market share is AEC. The Commission generally has not been receptive to those arguments.³⁴⁵ However, in *Nevada Power*, the Commission held that “[b]ecause of Nevada Power’s significant native load obligation, with no foreseeable prospect of that obligation being lifted, we agree that Available Economic Capacity is the more relevant measure in the Nevada Power market and, therefore, should be given more weight.”³⁴⁶ Nevada Power failed the market screens in its control area for Economic Capacity in eleven of the fourteen studied time periods, but only for one of the studied time periods for AEC. The Commission concluded that, under the AEC analysis, the market is not highly concentrated and would not become concentrated after the transaction closed.³⁴⁷

2. Implementation of EPC Act 2005 Section 203 Amendments

Section 1289 of EPC Act 2005 modifies the FERC’s jurisdiction over mergers and acquisitions and asset dispositions.³⁴⁸ Among other things, it changed the threshold level for asset transfers requiring FERC approval from \$50,000 to \$10,000,000.³⁴⁹ On December 23, 2005, the FERC issued a Final Rule to amend its regulations to implement the changes to section 203 of the FPA required by EPC Act 2005.³⁵⁰ In Order No. 669, the Commission made clear that, under section 203 as modified by EPC Act 2005, the \$10,000,000 limit triggering the Commission’s jurisdiction does not apply to a public utility’s merger or

342. 112 F.E.R.C. ¶ 61,052 at P 19.

343. *Nev. Power Co.*, 113 F.E.R.C. ¶ 61,265 at P 15 (2005).

344. *Id.*

345. *See, e.g., Okla. Gas & Elec. Co.*, 105 F.E.R.C. ¶ 61,297 at P 16 (2003).

346. 113 F.E.R.C. ¶ 61,265 at P 15. The Commission relied on a prior order in *Kansas City Power & Light Co.*, in which it found that AEC was the more relevant predictus than EC in the context of addressing a utility’s market-based rate authority under section 205 of the FPA. *Kansas City Power & Light Co.*, 113 F.E.R.C. ¶ 61,074 at P 35 (2005).

347. 113 F.E.R.C. ¶ 61,265 at P 18.

348. Energy Policy Act of 2005, Pub. L. No. 109-58, § 1289, 119 Stat. 594.

349. *Id.*

350. Order No. 669, *Transactions Subject to FPA Section 203*, F.E.R.C. STATS. & REGS. ¶ 31,200, 71 Fed. Reg. 1348 (2005) (to be codified at 18 C.F.R. pts. 2, 33) [hereinafter Order No. 669].

consolidation of its jurisdictional facilities with another, but instead only applies to a public utility's disposition of jurisdictional facilities, a public utility's acquisition of securities of public utilities, a public utility's purchases of existing generation facilities, and a holding company's acquisition of, or merger with, certain facilities. Thus, a public utility's proposal to merge or consolidate, directly or indirectly, [jurisdictional facilities] or any part thereof with those of any other person, by any means whatsoever, will be subject to the FERC's section 203 jurisdiction regardless of the dollar value of the facilities to be merged or consolidated.³⁵¹

EPAct 2005 gives the Commission jurisdiction over the purchase or acquisition by a holding company in a holding company system that includes a "transmitting utility" or an "electric utility" of a "transmitting utility," an electric utility, or another holding company system.³⁵² However, the Commission concluded that there would be no benefit in addressing on a case-by-case basis a holding company's purchase or acquisition of all types of "electric utility companies."³⁵³ Therefore, in Order No. 669 the Commission granted blanket authority to any holding company in a holding company system that includes a transmitting utility or an electric utility to purchase, acquire or take any security of:

- (i) a transmitting utility or company that owns, operates or controls only facilities used solely for transmission in intrastate commerce and/or sales of electric energy in intrastate commerce [i.e., within ERCOT, Alaska, and Hawaii];
- (ii) a transmitting utility or company that owns, operates, or controls only facilities used solely for local distribution and/or sales of electric energy at retail regulated by a state commission; or
- (iii) a transmitting utility or company if the transaction involves an internal corporate reorganization that does not present cross-subsidization issues and does not involve a traditional public utility with captive customers.³⁵⁴

In addition, the Commission concluded that there are certain financial or other arrangements undertaken by holding companies that, while subject to the Commission's jurisdiction under section 203(a)(2), do not harm competition or captive customers and, therefore, warrant blanket approval. These are transactions under which a holding company proposes to purchase, acquire, or take:

- (i) any non-voting security (that does not convey sufficient veto rights over management actions so as to convey control) in a transmitting utility, an electric utility company, or a holding company . . . that includes a transmitting utility or an electric utility company; or
- (ii) any voting security in a transmitting utility, an electric utility company, or a holding company. . . that includes a transmitting utility or an electric utility company if, after the acquisition, the holding company will own less than 10[%] of the outstanding voting securities; or

351. *Id.*

352. Energy Policy Act of 2005 § 1253.

353. Order No. 669, *supra* note 350, at P 55.

354. 18 C.F.R. § 33.1(c)(1)(i)–(iii) (2005).

- (iii) any security of a subsidiary company within a holding company system.³⁵⁵

However, the blanket authorization granted to a holding company for these three transactions involving securities are subject to the holding company not borrowing from any electric utility company subsidiary in connection with the acquisition or not pledging or encumbering the assets of any electric utility company subsidiary in connection with the acquisition.³⁵⁶ In addition, the Commission will require a holding company, granted a blanket authorization for the three security transactions, to submit to the Commission the same information that a holding company would have been required to submit to the SEC had the transactions occurred prior to the Act.³⁵⁷

In EPAct 2005, Congress also gave the Commission direct authority over the purchase, lease or acquisition of an "existing generation facility" that has a value in excess of \$10 million and is used for interstate wholesale sales subject to the Commission's ratemaking jurisdiction.³⁵⁸ In Order No. 669, the Commission defined "existing generation facility" as a generation facility that is operational at or before the time the transaction is consummated.³⁵⁹ The Commission also ruled that "operational" means that the generation facility is complete "i.e., it is capable of producing power."³⁶⁰ The FERC made clear that "operational" does not mean facilities that are only in the development or construction stage. However, the FERC also clarified that "operational" would include a facility that had been "mothballed," because that facility was operational at a time prior to consummation of the transaction. The Commission defined the phrase "the time the transaction is consummated" as "the point in time when the transaction actually closes and control of the facility changes hands."³⁶¹

With regard to whether the generation facility is used for interstate wholesale sales over which the Commission has ratemaking jurisdiction, in Order No. 669 the Commission established a rebuttable presumption that section 203 applies to any transfer of an existing generation facility unless the applicant can demonstrate with substantial evidence that the generator is used exclusively for retail sales.³⁶²

The Commission's general rule for transactions between non-affiliates will be to rebuttably presume that the transaction price agreed upon by the parties will be the market value of the subject assets, and the FERC will use that price to determine jurisdiction.³⁶³ However, the Commission recognized that it could not simply rely on the agreement of the parties if the transaction is between affiliates. The Commission's regulations indicate that if the transfer involves physical facilities, the Commission will determine the value based on the original cost

355. *Id.* § 33.1(c)(2).

356. 18 C.F.R. § 33.1(c)(3).

357. *Id.* § 33.1(c)(4).

358. Energy Policy Act of 2005, Pub. L. No. 109-58, § 1289, 119 Stat. 594 (amending Federal Power Act § 203(a)(1)(D)).

359. Order No. 669, *supra* note 350, at P 84; 18 C.F.R. § 33.1(b)(1).

360. Order No. 669, *supra* note 350, at P 85.

361. *Id.*

362. Order No. 669, *supra* note 350, at P 86.

363. *Id.* at P 98.

undepreciated as defined in the FERC's Uniform System of Accounts.³⁶⁴ If the transfer involves a jurisdictional contract, the value will be total expected nominal contract revenues over the remaining life of the contract. If the transaction involves securities, then the Commission will value the securities based on whether or not they are traded widely.³⁶⁵

EPAct 2005 requires the Commission to approve a proposed transaction

if it finds that the proposed transaction will be consistent with the public interest, and . . . not result in cross-subsidization of a non-utility associate company or the pledge or encumbrance of utility assets for the benefit of an associate company, unless the Commission determines that the cross-subsidization, pledge or encumbrance will be consistent with the public interest.³⁶⁶

In Order No. 669, the Commission defined "non-utility associate company" to be "any associate company in a holding company system other than a public utility or electric utility company that has wholesale or retail customers served under cost-based regulation."³⁶⁷

Order No. 669 requires section 203 applicants to demonstrate how their proposed transactions will avoid cross-subsidization to associate companies.³⁶⁸ The Commission created a new Exhibit M to be filed with each section 203 application in which an applicant must explain: either 1) how it is providing assurances that the proposed transactions will not result in cross-subsidization or improper pledges or encumbrances of utility assets or 2) if such results would occur, how those results are consistent with the public interest.³⁶⁹ Alternatively, an applicant may submit a verified statement indicating that "the proposed transaction does not result in, at the time of the transaction or in the future[.]" improper cross-subsidization, pledges or encumbrances.³⁷⁰

EPAct 2005 requires the Commission to act on section 203 applications in a timely fashion.³⁷¹ In Order 669, the Commission did not create an exhaustive list of the types of section 203 applications that would be processed on an expedited basis. However, the FERC indicated that it will generally expedite section 203 applications "that are not contested, are not mergers, and are consistent with Commission precedent."³⁷² These include applications proposing the disposition of only transmission facilities, particularly those in which the facilities before and after the transfer are under the control of a FERC-approved RTO or ISO, as well as applications that do not require an Appendix A analysis.³⁷³ The Commission also concluded that internal corporate reorganizations that do not present cross-subsidization issues are unlikely to cause anticompetitive effects. Thus, in Order No. 669, the FERC granted blanket authorization for such transactions if they also do not involve a traditional public utility with captive

364. Order No. 669, *supra* note 350, at P 116.

365. *Id.*

366. Energy Policy Act of 2005, Pub. L. No. 109-58, § 1289, 119 Stat. 594.

367. 18 C.F.R. § 33.1(b)(2) (2005).

368. Order No. 669, *supra* note 350, at P 163.

369. *Id.* at P 147.

370. Order No. 669, *supra* note 350, at P 169.

371. Energy Policy Act of 2005, Pub. L. No. 109-58, § 1289, 119 Stat. 594.

372. Order No. 669, *supra* note 350, at P 188.

373. *Id.* at PP 190-91; 18 C.F.R. § 33.11(b) (2005).

customers.³⁷⁴

I. Miscellaneous Procedural Developments

1. No-Action Letter Process

On November 18, 2005, the Commission issued an order clarifying that section 388.104(a) of its regulations, 18 C.F.R. § 388.104(a) (2005), may be used to request no-action letters, i.e., “informal advice on whether staff will recommend enforcement action if a matter under review is put into effect as proposed.”³⁷⁵ The process closely mirrors the no-action processes of the SEC and the Commodity Futures Trading Commission (CFTC).

Initially, the no-action letter process is available on a limited basis; it applies only to questions relating to whether particular transactions, practices, situations or other matters would violate the Standards of Conduct for Transmission Providers,³⁷⁶ Market Behavior Rules³⁷⁷ or, when issued, the final Prohibition of Energy Market Manipulation Rules.³⁷⁸ In addition, no fee will be charged for no-action letters initially.

“Requests for no-action letters should initially be submitted on a non-public basis to the General Counsel.”³⁷⁹ A request must describe in writing the proposed transaction, practice or situation in complete detail, including identifying to the extent possible each of the corporate entities, counterparties or persons that would be involved, the purpose of the matter, the requester’s role, and the regulatory issues involved. The General Counsel will not respond to purely hypothetical inquiries or to requests that relate to the merits of an on-the-record proceeding currently before the Commission.³⁸⁰ The request must be accompanied by a statement that, to the best of the requester’s personal information, knowledge and belief, the request is accurate and complete and does not contain any untrue statement of material fact, that there is no omission of material fact, and that the request does not raise any issue “that relates to the merits of an on-the-record proceeding currently before the Commission.”³⁸¹

The issuance of a response to a no-action letter request and the timing of any such response are entirely within the discretion of the General Counsel or designee.³⁸² In response to a request, the General Counsel or designee may state that staff:

- (1) will not recommend enforcement action if the matter is implemented as described in the request and in any additional information provided; [(2)] will not recommend enforcement action if the matter is implemented as so described only under conditions stated in the response, or as modified in the response; or (3) may

374. Order No. 669, *supra* note 350, at P 192.

375. *Informal Staff Advice on Regulatory Requirements*, 113 F.E.R.C. ¶ 61,174 at P 4 (2005).

376. 18 C.F.R. pt. 358.1 (2005).

377. *Investigation of Terms and Conditions of Public Utility Market-based Rate Authorizations*, 105 F.E.R.C. ¶ 61,218 (2003), *reh'g denied*, 107 F.E.R.C. ¶ 61,175 (2004); 18 C.F.R. §§ 284.288, 284.403 (2005); *Cinergy Mktg. & Trading, L.P. v. FERC*, Docket No. 04-1168 (D.C. Cir. May 28, 2004).

378. *Prohibition of Energy Market Manipulation*, 113 F.E.R.C. ¶ 61,067 (2005).

379. 113 F.E.R.C. ¶ 61,174 at P 9.

380. *Id.* at P 10.

381. *Informal Staff Advice on Regulatory Requirements*, 113 F.E.R.C. ¶ 61,174 at P 10 (2005).

382. *Id.* at P 12.

recommend enforcement action if the matter is implemented as so described.³⁸³

Until the date a response is issued, the request and other documents relating to it will remain non-public. Because the Commission believes that public disclosure of requests and responses is important to notify interested entities of the staff's views, any response to a no-action letter request and the request itself will be made public at the time of the response.³⁸⁴ However, the Commission recognizes that, in some cases, a request may contain confidential or proprietary information. Therefore, in unusual cases, a requester may seek non-public treatment, to the extent the request and response describe the proposed matter, for a specified period not to exceed 120 days from the date of response.³⁸⁵ If the staff disagrees with the non-public period requested, it will notify the requester, who may withdraw the request within thirty days of the staff notice. "In that case, the General Counsel or designee will not respond to the request, and the Commission . . . will treat the request and the staff notice as non-public."³⁸⁶

As with other informal advice, responses to no-action letter requests will not bind the Commission and will not operate as agency action subject to rehearing or judicial review. Any person who seeks a binding Commission determination concerning a proposed transaction, practice, situation or other matter may file a petition for a declaratory order pursuant to

18 C.F.R. § 385.207 (2005).³⁸⁷

2. Procedures for Disposition of Contested Audit Matters

The Commission has proposed to amend its regulations³⁸⁸ to permit any audited person to challenge staff audit findings and proposed remedies before the issuance of a Commission order on the merits of those audit matters.³⁸⁹ "The Commission's rules [currently] permit persons subject to *financial* audits to challenge staff audit findings before the issuance of a Commission order on the merits of those findings."³⁹⁰ Operational audits, however, address matters that are not explicitly covered by the existing provisions. Accordingly, the Commission proposes to provide *all* audited persons the same procedural benefits now provided for financial audits.³⁹¹

A Commission audit conducted under the FPA³⁹² may result in a notice of deficiency, audit report, or similar document containing findings of noncompliance with requirements with respect to, but not limited to: "(a) a filed

383. 113 F.E.R.C. ¶ 61,174 at P 13.

384. *Id.* at P 14.

385. 113 F.E.R.C. ¶ 61,174 at P 15.

386. *Id.* at P 16.

387. *Informal Staff Advice on Regulatory Requirements*, 113 F.E.R.C. ¶ 61,174 at P 17 (2005).

388. Notice of Proposed Rulemaking, *Procedures for Disposition of Contested Audit Matters*, F.E.R.C. Stats. & Regs. 32,592, 70 Fed. Reg. 65,866 (2005) [hereinafter *Procedures for Disposition*]. The Commission proposes to amend 18 C.F.R. parts 41 and 158 to apply to operational audits under the Federal Power Act (FPA) and the Natural Gas Act (NGA). For completeness, the Commission also proposes to amend parts 286 and 349 to include the same procedures for challenging audit findings and proposed remedies of audits conducted under the Natural Gas Policy Act (NGPA) and the Interstate Commerce Act (ICA). *Id.*

389. *Procedures for Disposition*, *supra* note 388.

390. *Id.* at P 6.

391. *Procedures for Disposition*, *supra* note 388.

392. The same process will apply to audits under the NGA, NGPA, and ICA. *Id.* at P 10.

tariff . . . , contract, data, records, accounts, books, communications or papers relevant to the audit . . . ; (b) matters under the Standards of Conduct or the Code of Conduct; and (c) the activities or operations of the audited person.”³⁹³ In addition, the notice of deficiency or audit report may contain proposed remedies. The Commission’s audit staff will communicate its findings and proposed remedies to the audited person.³⁹⁴

The audited person then must indicate in a written response its disagreement with any findings and/or proposed remedies. “Any initial order that the Commission subsequently may issue with respect to the notice of deficiency, audit report or similar document [will] note, but not [rule] on the merits [of], the . . . findings and any proposed remedies with which the audited person” signified disagreement.³⁹⁵ “The Commission [will] provide the audited person a specified number of days to respond [to issues] with which it disagreed.”³⁹⁶

Upon issuance of a Commission order, the audited person may “(a) acquiesce in the findings and proposed remedies by not timely responding to the Commission order, in which case the Commission may issue an order approving them or taking other action; or (b) challenge the . . . findings, and any proposed remedies, with which it disagreed by timely notifying the Commission in writing that it requests Commission review by means of a shortened procedure [(i.e., paper hearing)] or, if there are material facts in dispute which require cross-examination, a trial-type hearing.”³⁹⁷

If a person elects the shortened procedure, the Commission shall issue a notice setting a schedule for the filing of memoranda and reply memoranda by the audited person, Commission staff, and any other interested entities.³⁹⁸ Sections 41.4 and 41.5 of the Commission’s regulations apply to the form, style, and verification requirements of memoranda submitted pursuant to the regulations. Likewise, the formal requirements for filing found in Subpart T of 18 C.F.R. part 385 apply to all filings. A person consenting to the shortened procedure waives any right to subsequently request a hearing before an administrative law judge pursuant to existing section 41.7.³⁹⁹

J. PURPA

EPAct 2005 makes a number of modifications to the Public Utility Regulatory Policies Act of 1978 (PURPA).⁴⁰⁰ Section 1253 of EPAct 2005 has modified section 210 so that electric utilities will no longer be required to enter into new contracts to purchase electric energy from qualifying facilities (QFs) if the electric utility applies to the FERC and demonstrates that the QF has access to (i) independently administered auction-based day-ahead and real time wholesale markets for the sale of electric energy on a day-ahead and real-time

393. *Procedures for Disposition*, *supra* note 388 (proposing amendment to 18 C.F.R. § 41.1).

394. *Id.*

395. *Procedures for Disposition*, *supra* note 388 (proposing amendment to 18 C.F.R. § 41.1).

396. *Id.*

397. *Procedures for Disposition*, *supra* note 388 (proposing amendment to 18 C.F.R. § 41.2).

398. *Id.* (proposing amendment to 18 C.F.R. § 41.3). Only those participants filing initial memoranda may submit reply memoranda. *Procedures for Disposition*, *supra* note 388 (proposing amendment to C.F.R. § 41.3).

399. *Id.*

400. Public Utility Regulatory Policies Act of 1978, 16 U.S.C. § 2601 (2000).

basis as well as long-term capacity and energy markets; (ii) interconnection and transmission services administered by a RTO per an open access transmission tariff and meaningful competitive wholesale markets that provide an opportunity to sell short-term, and long-term capacity and electric energy, including long-term, short-term and real-time sales, or (iii) wholesale markets for the sale of capacity and energy that are, at a minimum, of comparable competitive quality as markets described in (i) and (ii).⁴⁰¹ An electric utility may file an application for relief from the mandatory purchase obligation on a service territory-wide basis. The FERC must act within ninety days of the application. A QF may apply to the FERC for an order reinstating the electric utility's obligation to purchase electric energy in the event of changed circumstances.⁴⁰²

Alliant Energy Corporate Services, on behalf of Interstate Power and Light Company and Wisconsin Power and Light Company (collectively, Alliant), sought to avail itself of these new provisions by filing a Petition for Declaratory Order (Petition) with the FERC requesting that the FERC determine that Alliant was not required to enter into a new contract or obligation to purchase electric energy from QFs.⁴⁰³ Specifically, Alliant argued that QFs situated in Alliant's service territory have nondiscriminatory access to competitive markets administered by the Midwest Independent Transmission System Operator. The FERC, however, denied the petition on procedural grounds, stating that Alliant and any others seeking relief from QF requirements must clearly identify to the FERC any QFs that would be affected—including existing QFs and those under development—and concluding that Alliant had not done so.⁴⁰⁴

Although not modifying the existing contract rights of any QFs, EPAct 2005 also modified the mandatory purchase requirement as it applied to new cogeneration QFs. Under new section 210(m)(2), such new QFs must meet new thermal output standards to be established by the FERC within six months of the enactment of EPAct 2005.⁴⁰⁵ As specified in new section 210(n), these new standards are to ensure that the output of a cogeneration QF is used "fundamentally" for commercial, industrial, or institutional purposes, and not for the sale of electricity.⁴⁰⁶ The FERC subsequently issued a final rule modifying the cogeneration qualification criteria so as to implement section 210(n) of PURPA.⁴⁰⁷

Prior to the passage of EPAct 2005, no more than fifty percent of a QF could be owned by an electric utility. EPAct 2005 eliminated this ownership limitation by modifying FPA section 3(17)(C) (defining "qualifying small power production facility") and 3(18)(B) (defining "qualifying cogeneration facility").⁴⁰⁸

401. Energy Policy Act of 2005, Pub. L. No. 109-58, § 1253, 119 Stat. 594 (adding section 210(m) of PURPA).

402. *Id.*

403. *Alliant Energy Corporate Servs., Inc.*, 113 F.E.R.C. ¶ 61,024 at P 1 (2005), reh'g pending.

404. 113 F.E.R.C. ¶ 61,024. See also *Montana-Dakota Util. Co.*, 113 F.E.R.C. ¶ 61,045 (2005) (application for waiver of mandatory purchase obligation dismissed on the same grounds).

405. Energy Policy Act of 2005 § 1253.

406. *Id.*

407. *Revised Regulations Governing Small Power Production and Cogeneration Facilities*, 114 F.E.R.C. ¶ 61,102 (2005).

408. Energy Policy Act of 2005, Pub. L. No. 109-58, § 1253, 119 Stat. 594.

ELECTRICITY REGULATION COMMITTEE

William M. Dudley, Chair
William D. DeGrandis, Vice Chair

Stephen Angle
Glenn S. Benson
Richard P. Bonnifield
Adrienne E. Clair
Jeffrey V. Conopask, Ph.D.
Noel J. Darce
Douglas E. Davidson
J. Kennerly Davis, Jr.
Jeffery S. Dennis
David M. DeSalle
Kevin M. Downey
Daniel P. Duthie
Russell A. Feingold
Daniel E. Frank
Gary E. Guy
James I. Ham
Raymond W. Hepper
James N. Horwood

Michael L. Kessler
Martin V. Kirkwood
William D. Kissinger
Jonathan A. Lesser
Tamara L. Linde
Patrick J. McCormick III
Keith R. McCrea
John T. Miller, Jr.
Gary A. Morgans
John A. Pirko
Perry D. Robinson
Regina Y. Speed-Bost
Robert A. Weishaar, Jr.
Andrew B. Young
Michael A. Yuffee
Belton T. Zeigler
Katherine C. Zeitlin