REPORT OF THE ELECTRICITY REGULATION & COMPLIANCE COMMITTEE

This report provides a summary of significant decisions, orders, or rules issued by the Federal Energy Regulatory Commission (the FERC or Commission) in 2009 in the electricity regulation and compliance area. The first part of the report addresses significant rulemaking orders and policy statements issued in 2009, while the remainder of the report addresses Commission orders in individual cases.

I. INTRODUCTION

The Electricity Regulation & Compliance Committee, which prepared this report, has a broad focus and overlapping jurisdiction with several other EBA committees. As these other committees have a more targeted focus, we have generally deferred to those other committees for a summary of the Commission's activities in their respective areas. Thus, this report does not generally address transmission reliability and planning (System Reliability, Planning & Compliance Committee), wholesale market-based rates (Power Generation & Marketing Committee), and demand-side management/renewable energy (Renewable Energy & Demand-Side Management Committee). In addition, this report does not generally address court appeals (Judicial Review Committee).

II. RULEMAKINGS AND POLICY STATEMENTS

A. Order Nos. 717-A and 717-B: Standards of Conduct for Transmission Providers

The FERC's Order No. 717-A[1] granted rehearing and clarification with respect to certain aspects of the FERC's rulemaking on standards of conduct. The Commission stated that the focus of Order No. 717 was to "make [the rules] clearer and to re-focus the rules on the areas with the greatest potential for abuse."[2] Among other things, the FERC determined in Order No. 717-A that: balancing load with energy or capacity is not, by itself, a transmission function;[3] granting or denying transmission service requests is a transmission function "regardless of the duration of the service requested;"[4] performing a system impact study or determining whether a transmission system can support a request for transmission service is a transmission function;[5] an officer or supervisor who disapproves a power sales contract does not become a marketing function

1. Order No. 717-A, *Standards of Conduct for Transmission Providers*, *order on reh'g and clarification*, 129 F.E.R.C. ¶ 61,043 (2009) (Order No. 717-A), *order on reh'g and clarification*, Order No. 717-B, 129 F.E.R.C. ¶ 61,123 (2009) (Order No. 717-B).

2. Order No. 717-A, 129 F.E.R.C ¶ 61, 043 at P 1.

3. *Id.* at P 24.

4. *Id.* at P 27.

5. *Id.*

employee by providing an explanation concerning the disapproval so long as he or she is not actively and personally engaged on a day-to-day basis in the contract negotiations;[6] resale or reassignment of transmission service is a marketing function;[7] *de minimis* off-system sales that are related to an local distribution company's (LDC) balancing requirements are not marketing functions;[8] incidental purchases or sales of natural gas by an affiliate of an interstate pipeline, for purposes of remaining in balance under applicable pipeline tariffs, are not marketing functions;[9] a pipeline shipper is not performing a marketing function when it assigns gas supply to its asset manager;[10] "information about a planned transmission outage is always transmission function information no matter how far in the future the planned transmission outage will occur;"[11] "meetings including both transmission function and marketing function employees are not barred under the Standards of Conduct as long as the meetings do not relate to transmission or marketing functions;"[12] the requirement to create records regarding certain classes of permitted communications, including information necessary to maintain or restore operation of the transmission system or generating units, or that may affect the dispatch of generating units, does not apply unless the information in question is transmission function information;[13] the recordation requirement is met by recording names, date, time, duration, and subject matter of communications;[14] the training requirement for supervisors applies to "supervisory employees who supervise other employees subject to the Standards [of Conduct] or who may come in contact with non-public transmission function information;"[15] and that the yearly training requirement applies on a calendar year, rather than a 365 day, basis.[16]

Order No. 717-A also found that "an employee in the legal, finance or regulatory division of a jurisdictional entity, whose intermittent day-to-day duties include the drafting and redrafting of non-price terms and conditions of, or exemptions to, umbrella agreements is a 'marketing function employee.'"[17] This led to several requests for expedited rehearing or clarification. In Order No. 717-B, the FERC clarified that the above language "was overly broad," and that the FERC intended to state "that an employee making business decisions about non-price terms and conditions can be considered a 'marketing function employee' because that employee is actively and personally engaged in marketing functions," but that "an employee who simply drafts or redrafts a contract, including non-price terms and conditions, without making business

6. *Id.* at P 83.
7. *Id.* at P 33.
8. *Id.* at P 68.
9. *Id.* at P 67.
10. *Id.* at P 63.
11. *Id.* at P 135.
12. *Id.* at PP 89-90.
13. *Id.* at PP 131-33.
14. *Id.* at P 134.
15. *Id.* at P 140.
16. *Id.* at P 142.
17. *Id.* at P 80.

decisions is not a 'marketing function employee.'"[18] Other requests for rehearing or clarification of Order No. 717-A remained pending at the end of 2009.

B. Order Nos. 719-A and 719-B: Wholesale Competition in Organized Markets

In Docket No. RM07-19, its investigation into selected means to improve the operation of *Wholesale Competition in Regions with Organized Electric Markets*,[19] the FERC issued two additional orders on rehearing in 2009. In Order No. 719-A, the FERC rejected challenges to its authority to adopt the requirement that Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) permit demand response (DR) aggregators to bid into their ancillary service markets (i.e., where the DR resource is technically capable of providing the ancillary service at issue) upon the same terms and conditions as are allowed to supply-side resources, explaining that DR improves reliability and can enhance the reasonableness of rates, objectives which it is authorized to pursue under Federal Power Act (FPA) sections 205 and 206.[20] It further noted that exercise of this authority did not override state interests in that its directive permitted states to affirmatively order that such participation would not be allowed to their regulated entities.[21] However, it granted rehearing at the request of the American Public Power Association (APPA) to direct that small utilities – those with sales of less than 4 million kWh per year – were to be presumed to oppose such participation unless they had acted to affirmatively authorize it.[22] It also clarified that, while it had not required that energy efficiency be accorded the same privilege as it lacked a record upon which it could do so, RTO/ISOs were free to adopt such rules and procedures if they chose using their stakeholder deliberation processes.[23]

In Order No. 719, the FERC directed each RTO/ISO to develop and file with it rules that would permit electricity prices to rise sufficiently during periods of operating reserve shortage that supply and demand will become balanced, stating four alternative approaches that it considered acceptable and six criteria to apply in evaluating whether to approve other innovative approaches that may be presented to it.[24] Numerous rehearing petitions challenging each of these determinations were filed, principally on the basis that permitting such price rises would subject ratepayers to the exercise of supplier market power and that DR responses were not sufficiently developed to avoid this result. The FERC rejected all of these arguments as raising no

18. Order No. 717-B, 129 F.E.R.C. ¶ 61,123 at P 6.

19. Order No. 719, FERC STATS. & REGS. ¶ 31,281, 73 Fed. Reg. 64,100 (2008) [hereinafter *Order No. 719*].

20. Order No. 719-A, 128 F.E.R.C. ¶ 61,059 at PP 13-71 (2009) [hereinafter *Order 719-A*]. Order No. 719-B provided significant additional clarifications respecting operation of this small utility affirmative approval provision, including that the provision applies to single retail customers seeking to bid DR into RTO/ISO markets, applies to the load-serving entity itself and its sub-contractors and that state retail authorities are free to regulate aggregator qualifications and approve or deny DR activities on an individual aggregator basis. 129 F.E.R.C. ¶ 61,252 at PP 4-27 (2009).

21. 128 F.E.R.C. ¶ 61,059 at PP 49, 65-71.

22. *Id.* at PP 51, 56-64.

23. *Id.* at P 16.

24. *Order No. 719*, *supra* note 19, at PP 192-94, 208, 246-247.

considerations not previously resolved in Order No. 719.[25] The FERC also rejected a rehearing request challenging its refusal to expand its investigation docket that led to Order No. 719 to more broadly examine whether organized markets are producing just and reasonable rates, asserting its right to structure its own proceedings and denying that its action violated due process.[26] Requests for rehearing were also made seeking reversal of (1) limitations placed in Order No. 719 upon the role of an internal Market Monitoring Unit (MMU) in participating in market mitigation activities to avoid creating conflicts of interest in the performance of such Unit's its functions; (2) limitations placed in Order 719 upon information the MMU is required to provide to State Commissions about market transactions and enforcement actions; (3) the timing and terms under which Order 719 requires that market offer and bid data be made public following market clearing, and (4) the criteria to measure and actions to be taken to demonstrate RTO/ISO responsiveness to market participants. All such rehearing applications were denied.[27]

C. Order Nos. 890-C and 890-D: Preventing Undue Discrimination and Preference in Transmission Service

In Order Nos. 890-C and 890-D,[28] the FERC addressed the final rehearing and clarification issues respecting its 2007 investigation on *Preventing Undue Discrimination and Preference in Transmission Service*.[29] In Order No. 890-C, the FERC clarified that, in its prior orders, it had not mandated that Available Transfer Capability (ATC) values developed by adjacent and interconnected transmission providers, and posted upon their open access web-sites, need be identical, but rather ordered that they be consistently developed employing North American Electric Reliability Corporation (NERC) guidance.[30] The FERC agreed with Petitioner Northwestern that a number of factors could cause ATC on such a transmission interconnection between two transmission providers to differ.[31] In Order No. 890-D, the FERC clarified that a buyer located on transmission system "A" buying system power from transmission system "B" could select to transmit the power either pursuant to network or point-to-point transmission rates on each system, and that undesignation and modeling to support the sale could be done on a "system" and not generating unit specific basis.[32]

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25. *Order No. 719-A*, *supra* note 20, at PP 72-106.

26. *Id.* at PP 111-122.

27. *Order No. 719A*, *supra* note 20, at PP 123-190.

28. Order No. 890-C, 126 F.E.R.C. ¶ 61,228 (2009) [hereinafter *Order No. 890-C*]; Order No. 890-D, 129 F.E.R.C. ¶ 61,126 (2009) [hereinafter *Order No. 890-D*].

29. Order No. 890, F.E.R.C. STATS. & REGS. ¶ 31,241, 72 Fed. Reg. 12,266 (2007) [hereinafter *Order No. 890*], *order on reh'g*, Order No. 890-A, F.E.R.C. STATS. & REGS. ¶ 31,261, 73 Fed. Reg. 2984 (2008), *order on reh'g and clarification*, Order No. 890-B, 123 F.E.R.C. ¶ 61,299 (2008).

30. *Order No. 890-C*, *supra* note 28, at PP 3-10.

31. *Id.* Review of the methodologies for calculation of ATC developed by NERC as required by Order No. 890 were examined by the Commission at separate Docket No. RM08-19. *See Mandatory Reliability Standards for the Calculation of Available Transfer Capability*, 129 F.E.R.C. ¶ 61,155 (2009). Review of this order is beyond the scope of this report.

32. *Order No. 890-D*, *supra* note 28, at PP 3-6.

D. Smart Grid Policy

On July 16, 2009, the FERC issued its Policy Statement on Smart Grid Policy (Smart Grid Policy Statement).[33] As explained in the Smart Grid Policy Statement, the Commission has jurisdiction over the transmission system under the FPA,[34] and is required under the Energy Independence and Security Act of 2007 (EISA)[35] to "adopt standards and protocols related to smart grid functionality and interoperability."[36] To guide the Commission in achieving that goal, the EISA contains a number of smart grid goals, and, as the Commission explained, this Policy Statement is intended to assist in the achievement of those goals by ensuring the interoperability of smart grid equipment.[37]

Under the EISA, the National Institute of Standards and Technology (NIST) is responsible for coordinating the development of smart grid devices, including the development of interoperability of such devices.[38] After EISA, in the opinion of the Commission, reaches "sufficient consensus" on the standards for the interoperability of smart grid devices, the Commission is required by the EISA to "adopt such standards and protocols as may be necessary to ensure smart-grid functionality and interoperability in interstate transmission of electric power, and regional and wholesale electricity markets."[39]

In issuing a proposed policy statement on these issues, the Commission has noted that the appropriate development of smart grid technology raised several essential challenges:

a) cybersecurity issues;

b) changes in generation, including the additional implementation of renewable generation sources producing variable power;

c) transportation technology issues created by the use of electricity loads with more variability; and

d) critical nature of standardization for smart grid technology.[40]

The Commission proposed to address these issues in the context of several themes: cybersecurity, physical security, "wide-area situational awareness," demand response, storage of electricity, and the use of electricity for transportation.[41]

As a preliminary matter, while the Commission acknowledged that the EISA does not alter the Commission's jurisdictional reach, it does add to the Commission's obligations by requiring the Commission to approve standards for smart grid functionality and interoperability.[42] As a result, the Commission characterized its authority as the ability "to adopt a standard that will be applicable to all electric power facilities and devices with smart grid features, including those at the local distribution level and those used directly by retail

33. *Smart Grid Policy*, 128 F.E.R.C. ¶ 61,060 (2009) [hereinafter *Smart Grid Policy*].

34. 16 U.S.C. §§ 824, 824a (2006).

35. Pub. L. No. 110-140, 121 Stat. 1492 (2007).

36. *Smart Grid Policy*, *supra* note 33, at P 2.

37. *Id.* at P 3.

38. *Id.*

39. EISA § 1305(d) (to be codified at 42 U.S.C. § 17385(d) (2006)).

40. *Smart Grid Policy*, *supra* note 33, at P 5.

41. *Id.* at P 6.

42. *Id.* at P 22.

customers so long as the standard is necessary for the purpose just stated."[43] Under the authority, the FERC stated that it could approve smart grid standards "if the Commission finds that such standards are necessary for smart grid functionality and interoperability in interstate transmission of electric power, and in regional and wholesale electricity markets."[44] However, the Commission acknowledged that because the EISA does not provide any enforcement authority, the enforcement of such standards and the authority to permit rate recovery for the implementation of smart grid technology is limited to its authority under the FPA.[45] Finally, the Commission noted that it expects the adoption of national smart grid standards not to interfere with the prerogatives of the states, noting that such standards should be flexible enough to adapt to the policy choices of each state related to metering, demand response, or similar smart grid functionality.[46]

In the Policy Statement, the FERC addressed the key priorities for smart grid interoperability. First, the Commission discussed cybersecurity, noting that the vulnerabilities of smart grid devices to attack.[47] The Commission explained that for it to consider approving a smart grid standard, the standard must incorporate its own cybersecurity protections or incorporate relevant cybersecurity protections embodied in either mandatory Reliability Standards or other smart grid standards.[48] The Commission emphasized that the smart grid standards should complement the cybersecurity-related Reliability Standards, and for that reason urged NIST to work with the NERC in the development of the standards.[49]

The next major area that the Commission addressed was the importance of coordination across inter-system interfaces.[50] Noting that the smart grid is really a system made of many smaller systems, the Commission stressed that the "common semantic framework" and software models that enable coordination across interfaces will be essential to achieve the goals of smart grid technology.[51] However, the FERC explained that during the transition period in the initial stages of smart grid implementation, older software systems will continue to be used, and that appropriate technology should be developed to allow legacy devices to provide the necessary information to smart grid components.

The Commission also emphasized the importance of "wide-area situational awareness."[52] This leverages the ability of smart grid technology to enhance system reliability by providing system operators with more information regarding the status of generation, load, and transmission.[53] As the FERC explained, this greater awareness should speed reaction times during a reliability

43. *Id.*
44. *Id.*
45. *Id.* at P 23.
46. *Id.* at P 27.
47. *Id.* at P 40.
48. *Id.* at P 41.
49. *Id.* at PP 42-43.
50. *Id.* at P 51.
51. *Id.*
52. *Id.* at P 61.
53. *Id.*

event, and for that reason should be a critical component of smart grid standard development.[54]

The Commission then stressed the importance of smart grid standards for demand response, noting the potential of smart grid technology to promote this ability.[55] The Commission noted that the greater use of smart grid-enabled demand response can reduce price volatility, reduce generator market power, and aid the integration of variable "green" generation into the market.[56] According to the FERC, demand response smart grid interoperability standards should address all customer classes, including residential, commercial, and large industrial customers, and should be able to work in both mandatory and voluntary demand response regimes.[57]

Noting the growing importance of electric storage, the Commission explained that such storage can be very important for the electric system, and smart grid standards related to such storage should be a priority.[58] The Commission also explained the electric transportation should be a priority, explaining that widespread use of electric transportation could have reliability implications for the bulk-power system.[59] For that reason, the Commission urged the development of smart grid standards that will assist utility companies with the charging of electric vehicles during off-peak hours.[60]

The Commission also stated its interim rate policy for the development and implementation of smart grid technology by transmission companies, stating that this was intended to assist utilities with the recovery of the cost of smart grid implementation under certain circumstances.[61] The Commission explained that a company seeking to ensure the recovery of such costs must make either file a petition for a declaratory order or make an FPA section 205 filing containing the relevant showings.[62]

As the Commission explained, for an applicant to be able to recover the cost of smart grid investment, the applicant must make four showings: (1) "that the smart grid facilities will advance the goals of EISA section 1301;" (2) that the reliability and cybersecurity of the bulk-power system will not be harmed; (3) that chances of stranded investment in smart grid technology due to its implementation before the development of interoperability standards have been minimized; and (4) that the applicant will assist in the interoperability standards development process by agreeing to share relevant information with the Department of Energy Smart Grid Clearinghouse.[63]

In describing the rate recovery at issue, the Commission explained that single issue rate treatment for the recovery of smart grid costs will be accepted,[64]

54. *Id.* at P 62.
55. *Id.* at P 74.
56. *Smart Grid Policy*, *supra* note 33.
57. *Id.* at P 75.
58. *Id.* at P 81.
59. *Id.* at P 90.
60. *Id.* at P 91.
61. *Id.* at P 103.
62. *Smart Grid Policy*, *supra* note 33.
63. *Id.* at P 122.
64. *Id.* at P 136.

including the recovery of stranded costs for legacy systems that would be replaced by new smart grid equipment.[65] The FERC also noted that companies may request accelerated depreciation and abandonment authority under FPA section 205.[66] Finally, the Commission explained that rate recovery filings for projects receiving grant funding from the Department of Energy (DOE) will not be considered differently.[67]

E. Order No. 676-E: Standards for Business Practices and Communications Protocols for Public Utilities

On November 24, 2009, the FERC issued Order No. 676-E to incorporate by reference in its regulations the latest version (Version 002.1) of certain business practice standards adopted by the Wholesale Electric Quadrant (WEQ) of the North American Energy Standards Board (NAESB).[68] The revised standards update an earlier version of the standards the FERC previously incorporated by reference in Order No. 676-C.[69] The majority of changes included in the Version 002.1 standards were made to support the requirements established by the FERC in Order Nos. 890, 890-A, and 890-B, in which the FERC created measures to prevent undue discrimination under the *pro forma* open access transmission tariff (OATT).[70]

The Version 002.1 standards modified NAESB's Commercial Timing Table (WEQ-004 Appendix D) and Transmission Loading Relief Standards (WEQ-008) to clarify and coordinate NAESB's business practice standards with those of the NERC.[71] The Version 002.1 standards also revised certain ancillary services definitions contained in the Open Access Same-Time Information Systems Standards (WEQ-001) related to demand response resources inclusion as potential ancillary services providers.[72] The FERC determined that incorporating the Version 002.1 standards will facilitate transmission customers' ability to receive service on a non-discriminatory basis and assist the FERC in supporting necessary infrastructure and the reliability of the interstate transmission grid.[73]

The FERC issued a Notice of Proposed Rulemaking (NOPR) on March 19, 2009, proposing to incorporate the Version 002.1 standards. Fourteen parties from various industry segments filed comments in response to the NOPR. The FERC addressed several of the technical issues raised by parties and reaffirmed its belief in the practice of incorporation by reference of standards developed through the NAESB process as opposed to development of such standards

65. *Id.* at P 141.

66. *Id.* at P 149.

67. *Id.* at P 156.

68. *Standards for Business Practices and Communications Protocols for Public Utilities*, Order No. 676-E, 129 F.E.R.C. ¶ 61,162 (2009) [hereinafter *Order No. 676-E*].

69. Order No. 676-C, *Standards for Business Practices and Communication Protocols for Public Utilities*, F.E.R.C. STATS. & REGS. ¶ 31,274 (2008), *order on reh'g and clarification*, Order No. 676-D, 124 F.E.R.C. ¶ 61,317 (2008).

70. Order No. 697-E at P 10.

71. 129 F.E.R.C. ¶ 61,162 at P 2.

72. *Id.*

73. *Id.* at P 138.

through FERC-sponsored technical conferences and formal rulemakings.[74] The FERC noted that because the NAESB process was open and fair, it gave significant weight to industry consensus.[75] Following a review of the standards against the requirements in Order No. 890, the FERC determined that with the exception of a small number of cases addressed in the Final Rule, the Version 002.1 standards satisfied these requirements.[76]

The Final Order required public utilities to modify their OATTs to include the standards that the FERC incorporated by reference. Recognizing the time needed to plan and complete tasks involved in implementing the standards, the FERC required that the tariff filings be made at least ninety days before the compliance date (i.e., on or before the first day of the first quarter occurring 365 days after approval of the NERC Reliability Standards addressed in Docket No. RM08-19 by all applicable regulatory authorities).[77] The FERC clarified that "to the extent a public utility's OASIS obligations are administered by an independent system operator (ISO) or regional transmission operator (RTO) and are not covered in the public utility's OATT, the public utility will not need to modify its OATT to include the OASIS standards."[78]

F. Transmission Planning Process Under Order No. 890 (Docket No. AD09-8)

In 2007, the FERC issued Order No. 890, which, among other things, directed transmission providers to develop transmission planning processes that satisfied nine specific principles and to memorialize those processes in a new Attachment K, which would become part of their OATTs.[79] The issuance of Order No. 890 was followed by several FERC-sponsored regional technical conferences in 2007 to assist transmission providers to develop these processes, the filing with the FERC of their Attachment Ks, and finally the issuance by the FERC of a series of orders throughout 2008 addressing the adequacy of the filed Attachment K.[80] In these orders, the FERC noted that its staff would monitor the implementation of these various transmission planning processes and would convene an additional series of technical conference in 2009 to determine whether further refinements and improvements in the processes might be appropriately informed by experience gained through their initial

74. *Id.* at PP 116-118.

75. *Id.* at P 11.

76. *Id.*

77. *Id.* at P 128.

78. *Id.* at P 16.

79. Order No. 890, *supra* note 29, at PP 418-602.

80. *PJM Interconnection, L.L.C.*, 123 F.E.R.C. ¶ 61,163 (2008); *Midwest Independent System Operator Inc.*, 123 F.E.R.C. ¶ 61,164 (2008); *American Transmission Co., L.L.C.& Midwest Independent System Operator, Inc.*, 123 F.E.R.C. ¶ 61,165 (2008); *MidAmerican Energy Co*., 123 F.E.R.C. ¶ 61,160 (2008); *ISO New England Inc.*, 123 F.E.R.C. ¶ 61,161 (2008); *Maine Public Service Co.*, 123 F.E.R.C. ¶ 61,162 (2008); *Cal. Indep. Sys. Operator Corp*., 123 F.E.R.C. ¶ 61,283 (2008); *El Paso Electric Co.*, 124 F.E.R.C. ¶ 61,051 (2008); *Xcel Energy Services, Inc. – Southwestern Public Service Co.*, 124 F.E.R.C. ¶ 61,029 (2008); *Idaho Power Co.*, 124 F.E.R.C. ¶ 61,053 (2008); *United States Department of Energy – Bonneville Power Administration*, 124 F.E.R.C. ¶ 61,054 (2008); *Cleco Power, L.L.C.*, 124 F.E.R.C. ¶ 61,264 (2008); *Duke Energy Carolinas, L.L.C.*, 124 F.E.R.C. ¶ 61,267 (2008); *Entergy Services, Inc.*, 124 F.E.R.C. ¶ 61,268 (2008); *E.ON U.S., L.L.C.*, 124 F.E.R.C. ¶ 61,263 (2008); *South Carolina Electric & Gas Co.*, 124 F.E.R.C. ¶ 61,266 (2008); *Southern Company Services, Inc*., 124 F.E.R.C. ¶ 61,265 (2008); *Southwestern Power Admin*., 124 F.E.R.C. ¶ 61,261 (2008); *Progress Energy*, 125 F.E.R.C. ¶ 61,006 (2008).

implementation. On June 30, 2009, the FERC announced that it would convene three such technical conferences at three locations across the country.[81]

On October 8, 2009, following the completion of the technical conferences, the FERC issued a Notice of Request for Comments in Docket No. AD09-08 seeking comment on the adequacy of the various regional transmission planning processes and of the existing mechanisms for the initial funding, recovery, and allocation among transmission customers of the costs associated with new transmission.[82] More than 100 sets of Initial Comments and forty-seven sets of Reply Comments were filed in response to the Notice of Request for Comments. Entities submitting comments included all of the major trade associations, transmission providers, transmission dependent utilities, various state regulatory commissions, government agencies, public advocacy groups, and several elected officials. Entities submitting comments offered different perspectives on whether existing transmission planning processes were working or needed improvement, and likewise differed on whether existing mechanisms for the funding and allocation of the costs associated with new transmission needed to be modified.

III. RTO/ISO/REGIONAL DEVELOPMENTS

A. ISO New England

1. Forward Capacity Market Auctions, Capacity-Related Market Rule Changes and Complaints

During 2009, a series of FERC orders reflected New England's focus on the implementation and refinement of the Forward Capacity Market (FCM). Under the FCM, an initial auction, referred to as a Forward Capacity Auction (FCA), is held three years in advance of identified capacity need, and subsequent auctions, referred to as reconfiguration auctions, that allow minor quantity adjustments and facilitate the trading of commitments, are held as the year of need approaches. On April 16, the FERC accepted the results of the second FCA for the 2011/2012 Capacity Commitment Period.[83] Results for the third FCA for the 2012/2013 Capacity Commitment Period were filed October 30, 2009,[84] and the FERC concurred, on a one-time basis, with changes made by the ISO New England (ISO-NE) market monitor mitigating one market participant's proposed bid to remove its capacity from the market that had been challenged and set for paper hearing.[85] Challenges to ISO-NE filings for the first FCA for the 2010/2011 Capacity Commitment Period remained pending before the FERC at year end.[86]

81. Notice of Technical Conferences, Docket No. AD09-8 (June 30, 2009).

82. Notice of Request for Comments, Docket No. AD09-8 (October 8, 2009).

83. *ISO New England Inc.*, 128 F.E.R.C. ¶ 61,028 (2009).

84. *See generally ISO New England Inc., Forward Capacity Auction Results Filing*, Docket No. ER10-186 (Oct. 30, 2009).

85. *ISO New England Inc.*, 128 F.E.R.C. ¶ 61,266 (2009).

86. *See generally ISO New England Inc.*, 123 F.E.R.C. ¶ 61,290 (2008), *reh'g pending;* Informational Filing with Proration Results, *ISO New England Inc.*, Docket No. ER08-633 (Nov. 28, 2008).

The FERC accepted throughout the year a number of modifications to New England's FCM and capacity-related market rules. In January, the FERC accepted changes refining and integrating the generator interconnection process with the FCM.[87] The FERC accepted in February a consolidated set of amendments to the FCM rules for bilateral contracts and reconfiguration auctions.[88] In June, the FERC accepted changes requiring capacity imports into New England from northern New York (NNY Capacity Resources) to offer the energy from those resources at levels intended to comport more closely to the cost of such energy.[89] Changes that amended the reconfiguration auction rules were accepted in September,[90] and enhanced procedures for scheduling and curtailment priorities for transactions used to export energy and capacity to other control areas were accepted in October.[91] Numerous additional clarifications and changes,[92] as well as limited waivers,[93] to the FCM rules were also accepted by the FERC. The region's stakeholders addressed a number of other, open FCM issues in a specially tailored stakeholder forum during the latter part of 2009.[94]

In April, based on factual allegations in the twice amended filing by ISO-NE and the New England Power Pool (NEPOOL) regarding the use of competitive offer requirements for energy transactions associated with installed capacity import contracts and related penalty provisions,[95] the Connecticut Attorney General and the Connecticut regulators and consumer advocate filed complaints against ISO-NE and certain market participants that import NNY Capacity Resources charging that the conduct of the NNY Capacity Resources

87. *ISO New England Inc. & New England Power Pool*, 126 F.E.R.C. ¶ 61,080 (2009).

88. *ISO New England Inc. & New England Power Pool Participants Comm.*, 126 F.E.R.C. ¶ 61,115 (2009).

89. *ISO New England Inc. & New England Power Pool*, 127 F.E.R.C. ¶ 61,235 (2009).

90. *ISO New England Inc. & New England Power Pool*, Docket No. ER09-1569-000 (Aug. 10, 2009) (unpublished letter order).

91. *ISO New England Inc. & New England Power Pool*, Docket No. ER09-1408-000 (Oct. 9, 2009) (unpublished letter order).

92. *See, e.g.*, *ISO New England Inc. & New England Power Pool Participants Comm.*, 127 F.E.R.C. ¶ 61,238 (2009) (Omnibus 4 Changes); *ISO New England Inc. & New England Power Pool Participants Comm.*, 128 F.E.R.C. ¶ 61,023 (2009), *reh'g requested* (FCM Phase II: Rights and Obligations); *ISO New England Inc. & New England Power Pool Participants Comm.*, Docket No. ER09-1136 (Jun. 16, 2009) (unpublished letter order); *ISO New England Inc. & New England Power Pool*, Docket No. ER09-1746 (Nov. 18, 2009) (unpublished letter order) (Real-Time Emergency Generation Capacity Supply Obligation Transfers).

93. *See, e.g.*, *PSEG Power Connecticut, L.L.C.*, 126 F.E.R.C. ¶ 61,062 (2009); *ISO New England Inc.*, 127 F.E.R.C. ¶ 61,242 (2009); *National Grid USA & Laidlaw Berlin BioPower, L.L.C.*, 129 F.E.R.C. ¶ 61,212 (2009)

94. At the request of New England state regulators, an FCM Working Group (FCMWG) was created to provide a stakeholder forum specifically constructed for the consideration of FCM design changes. The FCMWG assumed responsibility for reviewing all open FCM issues and assessing which issues could be addressed in time for a February 2010 filing. The FCMWG produced a design basis document that received broad support from the New England States and NEPOOL members, but was not supported by ISO-NE. Further efforts among the parties ultimately resulted in the identification of rule changes supported by ISO-NE, state representatives and NEPOOL.

95. *See, e.g.*, *ISO New England Inc. & New England Power Pool*, *Tariff Revisions Regarding Competitive Offer Requirement for Capacity Imports*, Docket No. ER09-873-000 (Mar. 20, 2009); Corrections filed by ISO New England Inc., Docket No. ER09-873 (May 6 and 20, 2009); *ISO New England Inc. & New England Power Pool*, 127 F.E.R.C. ¶ 61,235 (2009) (accepting tariff revisions, subject to refund, and requiring further compliance filing to explain a proposed penalty exemption); *ISO New England Inc.*, 127 F.E.R.C. ¶ 61,235 (2009) (accepting compliance filing).

demonstrated those Resources never intended to provide energy associated with their capacity and requesting disgorgement of profits and imposition of civil penalties.[96] Further, the complaints alleged that the fact that the offending conduct transpired over more than two years demonstrated that ISO-NE's market monitoring arrangements needed to be amended. In response, the FERC consolidated the complaints, summarily rejected as unsupported the request to modify the market monitoring arrangements and, citing the unique history of ISO-NE's allegations regarding the NNY Capacity Resources' bidding strategy, set the complaints against the NNY Capacity Resources for an evidentiary hearing.[97] Prehearing activities began in early September, 2009, with hearings currently scheduled to commence in May 2010 and an initial decision to be issued in August, 2010.[98]

In other capacity-related complaints, the FERC denied a May 5, 2009 complaint by Boralex Ashland, L.P. seeking transmission priority for its capacity imports over the New Brunswick interface, finding ultimately that Boralex's firm transmission rights did not include any capacity import rights.[99] The FERC also denied a complaint by several municipal utilities and organizations challenging ISO-NE's decision to discontinue special treatment, for capacity credit purposes, of firm power imported into New England from the Niagara and St. Lawrence-FDR projects operated by the New York Power Authority.[100]

2. Installed Capacity Requirements

Efforts to identify the resource adequacy requirements for New England continued to be demanding and contentious during 2009. Under current arrangements, ISO-NE files the reliability requirements of the region with the FERC for acceptance or approval ninety days prior to the applicable primary or annual reconfiguration FCA.[101] The final regional reliability requirements (ICR) for the 2009/2010 capability year, as well as the ICR for the primary 2012/2013 FCA and the second 2010/2011 capability year reconfiguration auction, were filed and accepted by the FERC.[102] In December, however, ISO-NE and NEPOOL filed competing proposals for the ICR to be used for the final 2010/2011 reconfiguration auction, unable to agree on how the reliability benefits of New England's ties to other Control Areas should be accounted

96. *See, e.g.,* The Connecticut Representatives' Consolidated Amended Complaint Seeking An Investigation, Hearing, Disgorgement, and Penalties, *Richard Blumenthal, Attorney General for The State of Conn. v. ISO New England Inc.* 128 F.E.R.C. ¶ 61,182 (2009).

97. *Id*.

98. Order Modifying Procedural Schedule, Docket Nos. EL09-47-000 and EL09-48-000 (consolidated) (Nov. 24, 2009) at P 2.

99. *Boralex Ashland, L.P. v. ISO New England Inc.*, 128 F.E.R.C. ¶ 61,028 (2009).

100. *Conn. Mun. Elec. Energy Coop., Mass. Mun. Wholesale Electric Co., Pascoag (RI) Util. District, and Vermont Dept. of Public Service v. ISO New England Inc.*, 128 F.E.R.C. ¶ 61,270 (2009).

101. *See, e.g.,* ISO-NE Tariff, § III.12.3. The Installed Capacity Requirement is a measure of the installed resources that are projected to be necessary to meet reliability standards in light of total forecasted load requirements for the New England Control Area and to maintain sufficient reserve capacity to meet reliability standards.

102. *ISO New England Inc. & New England Power Pool Participants Comm.*, 127 F.E.R.C. ¶ 61,142 (2009) ; *ISO New England Inc.*, Docket No. ER09-1415 (Aug. 14, 2009) (unpublished letter order); *ISO New England Inc. & New England Power Pool Participants Comm.*, Docket No. ER09-640 (Mar. 11, 2009) (unpublished letter order).

for.[103] That filing also included competing proposals to change the market rules that specify the calculation method for identifying the ICR, which will require the FERC, for the first time since ISO-NE began operations as the New England RTO, to determine the applicability and operation of the so-called "jump ball" provisions of the Participants Agreement.[104] As of year-end 2009, that filing was pending before the FERC. It is also worth noting that long-standing litigation over authority to establish the resource adequacy requirements for the region drew to a close. In September, the U.S. Court of Appeals for the D.C. Circuit rejected challenges by state regulators to the FERC's jurisdiction over the annual reliability values.[105]

3. Reducing Credit Exposure - Financial Assurance and Billing Policy Changes

Largely in response to concerns raised by the credit crisis that began in 2008, changes to the ISO-NE financial assurance policy provisions related to unsecured credit and letters of credit were extensively considered. In the meantime, the FERC approved incremental changes to reduce exposure for unpaid charges, by accelerating the billing of certain energy charges, and permitting pre-payments and account auto-debiting,[106] and by shortening the billing cycle and accelerating payment to net sellers.[107] The ISO-NE financial assurance policies were refined and consolidated from three into one policy.[108] Additionally, the financial assurance and billing policies were amended to conform the FCM-related provisions of the policies to the FCM market rules, to reduce confusion experienced with the billing and collection of the deposits associated with the FCM qualification process, and to correct the treatment afforded certain non-commercial capacity resources.[109]

4. Out-of-Market Reliability Costs

On July 2, 2009, the FERC denied rehearing of its July 2008 order addressing out-of-market reliability costs incurred in southeastern Massachusetts, known as "local second contingency protection resource charges", and efforts of certain Massachusetts public power systems (MPS) to

103. *ISO New England Inc., Installed Capacity Requirement and Related Values for the Final Reconfiguration Auction for the 2010/2011 Capability Year and Certain Market Rule Changes*, Docket No. ER10-437-000 (Dec. 15, 2009).

104. *See, e.g.*, PARTICIPANTS AGREEMENT AMONG ISO NEW ENGLAND INC. AND THE NEW ENGLAND POWER POOL § 11.1.5 (2009), *available at* http://www.iso-ne.com/regulatory/part_agree/index.html.

105. Conn. Dept. of Pub. Util. Control v. FERC, 569 F.3d 477 (D.C. Cir. 2009).

106. *ISO New England Inc. & New England Power Pool Participants Comm.*, Docket No. ER09-454 (Feb. 6, 2009) (unpublished letter order).

107. *ISO New England Inc. & New England Power Pool*, Docket No. ER09-932 (Apr. 29, 2009) (unpublished letter order).

108. *ISO New England Inc. & New England Power Pool Participants Comm.*, Docket No. ER09-1470 (Aug. 21, 2009) (unpublished letter order).

109. *See, e.g., ISO New England Inc. & New England Power Pool Participants Comm.*, Docket No. ER10-62-000 (Nov. 10, 2009) (unpublished letter order); *ISO New England Inc. & New England Power Pool Participants Comm.*, Docket No. ER09-1721-000 (Oct. 20, 2009) (unpublished letter order); *ISO New England Inc. & New England Power Pool, Revisions to Financial Assurance Policies*, Docket No. ER10-423-000 (Dec. 15, 2009).

shift some or all of those costs from them to others.[110] The MPS appealed those decisions to the U.S. Court of Appeals for the D.C. Circuit.[111] In response to the requirements of the 2008 order, ISO-NE filed in July its report on the outcome of the stakeholder process on the topic, indicating that it did not plan to modify the southeastern Massachusetts zone, but that the circumstances causing the large out-of-market charges had been largely remedied through a combination of transmission upgrades and changes in dispatch by its operators pursuant to revised guidelines that it included in the filing.[112] The MPS challenged the conclusions in the report not to modify the southeastern Massachusetts zone or provide other monetary relief, but that challenge was rejected.[113]

Pending full implementation of FCM in June 2010, there remained in place a number of reliability must run (RMR) agreements.[114] Litigation to terminate one of the region's RMR agreements on financial eligibility grounds, in part because of the additional market payments from the FCM transition period,[115] was resolved through settlement.[116] The FERC accepted changes to the remaining RMR agreements that permit recovery of environmental compliance costs incurred in connection with regulatory requirements imposed by the Regional Greenhouse Gas Initiative.[117] An appeal to the DC Circuit Court of the FERC orders regarding the RMR arrangements in the State of Connecticut was dismissed by that Court.[118]

Additionally, the FERC conditionally accepted, subject to the outcome of the region's Order No. 719 compliance filing proceeding summarized below and to a thirty day compliance filing, revisions to the way in which the offer of a resource that is committed to satisfy local and system-wide reliability needs may be mitigated under conduct thresholds by the ISO-NE market monitor.[119] ISO-NE submitted the required compliance filing on October 30, 2009, and that

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110. *Braintree Light Dep't v. ISO New England Inc.*, 129 F.E.R.C. ¶ 61,008 (2009). *Braintree Mun. Light Dep't v. ISO New England Inc.*, 124 F.E.R.C. ¶ 61,061 (2008) (the FERC granted the MPS complaint but sent the matter back to New England for discussion among MPS, other stakeholders, and ISO-NE).

111. Braintree Electric Light Dep't v. FERC, No. 09-1231 (D.C. Cir. 2009).

112. *Braintree Light Dep't v. ISO New England Inc.*, *Report of Compliance,* 129 F.E.R.C. ¶ 61,077 (2009).

113. *Braintree Light Dep't v. ISO New England Inc.*, *Order on Compliance Filing,* 129 F.E.R.C. ¶ 61,077 (2009).

114. Under the FCM Settlement, the region's RMR agreements are to remain in effect until the earlier of full implementation of the FCM (June 2010) or a determination that they are no longer needed for reliability. So long as they remain in effect, capacity payments received by those resources during the FCM Transition Period reduce payments under the RMR agreements. In light of such payments, however, the FERC indicated that the continuing financial eligibility of an RMR agreement may be challenged. *See, e.g.*, *Milford Power Co., L.L.C.*, 119 F.E.R.C. ¶ 61,167, *reh'g denied*, 121 F.E.R.C. ¶ 61,042 (2007).

115. *Ashburnham Mun. Light Dept. v. Berkshire Power Co., L.L.C. & ISO New England Inc.*, *Complaint of Municipal Light Departments and Massachusetts Municipal Wholesale Electric Co.,* Docket No. EL09-3-000 (Oct. 8, 2008).

116. *Ashburnham Mun. Light Dept. v. Berkshire Power Co., L.L.C. & ISO New England Inc.*, *Joint Offer of Settlement,* Docket No. EL09-3 (Dec. 22, 2009).

117. *See e.g.*, *Middletown Power, L.L.C. & Montville Power, L.L.C.*, Docket No. ER09-384-000 (Jan. 8, 2009); *Pittsfield Generating Co., L.P.*, Docket No. ER09-434-000 (Jan. 29, 2009); *NAEA Energy Massachusetts, L.L.C.*, Docket No. ER09-487-000 (Feb. 3, 2009); *PSEG Power Connecticut, L.L.C.*, Docket No. ER09-507-000 (Feb. 3, 2009) (each unpublished letter orders).

118. Richard Blumenthal, Attorney Gen. for the State of Conn. v. FERC, 552 F.3d 875 (D.C. Cir. 2009).

119. *ISO New England Inc. & New England Power Pool*, 129 F.E.R.C. ¶ 61,008 (2009).

compliance filing was contested and remained pending before the FERC at the end of the year. Changes to reduce congestion costs incurred to maintain local reserves and changes to increase the efficiency of dispatch and pricing were accepted in December.[120]

5. Order No. 719 Compliance Filings; Price-Responsive Demand

The New England region also submitted its response to Order Nos. 719 and 719-A and had active efforts underway to evaluate the future treatment of price-responsive demand (PRD) in the New England wholesale electricity markets. New England's Order No. 719 compliance filing was submitted on April 28, 2009,[121] with proposed changes in all four Order No. 719 categories. On the RTO responsiveness issue, the Order No. 719 filing described, and ISO-NE has already implemented, plans to form a "Consumer Liaison Group" and for enhanced reporting on ISO-NE Board and Board Committee activities. In response to Order No. 719-A, ISO-NE and NEPOOL jointly filed changes to address the treatment of retail customer aggregators that participate in the wholesale capacity and electricity markets.[122] The Order Nos. 719 and 719-A compliance filings were still pending before the FERC at the end of 2009.

With respect to PRD, the region reported on its progress, proposed for ISO-NE to file market rule refinements on or before June 1, 2010, and committed ISO-NE to file additional progress reports.[123] In the meantime, the Real-Time Price Response Program and the Day-Ahead Load Response Program were extended through May 31, 2012.[124] Further, because PRD efforts, as well as the FCM Working Group efforts described above, could produce outcomes or recommendations potentially relevant to future discussions of load reconstitution for demand resources, ISO-NE and NEPOOL filed a report in September noting regional agreement to defer discussions on this topic until February 2010.[125]

B. New York Independent System Operator

On October 16, 2008, the Commission issued an order addressing a December 7, 2007 filing by the NYISO submitted in compliance with the planning requirements of Order No. 890, as supplemented by a June 18, 2008 filing submitted by the NYISO and the New York Transmission Owners (NYTOs).[126] The December 7 filing proposed a new Comprehensive System Planning Process based on the Comprehensive Reliability Planning Process (CRPP) then in place under Attachment Y to the NYISO OATT. At that time,

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120. *ISO New England Inc. & New England Power Pool Participants Comm.*, Docket No. ER10-97-000 (Dec. 15, 2009) (unpublished letter order).

121. *ISO New England Inc. & New England Power Pool, Filing of ISO New England, Inc. & New England Power Pool,* Docket No. ER09-1051-000 (Apr. 28, 2009).

122. *ISO New England Inc. & New England Power Pool, Filing of ISO New England Inc. & New England Power Pool in Compliance with Order No. 719-A,* Docket No. ER09-1051-000 (Oct. 27, 2009).

123. *ISO New England Inc. & New England Power Pool, Report Regarding Treatment of Price-Responsive Demand in the New England Electricity Markets,* Docket No. ER08-830-000 (Jul. 31, 2009).

124. *ISO New England Inc. & New England Power Pool*, Docket No. ER09-1737-000 (Oct. 29, 2009) (unpublished letter order).

125. *ISO New England Inc. & New England Power Pool*, *Report Regarding Load Reconstitution for Demand Resources*, Docket No. ER09-1666-000 (Sept. 1, 2009).

126. *N.Y. Indep. Sys. Operator, Inc.*, 125 F.E.R.C. ¶ 61,068 (2008).

the CRPP was focused only on reliability upgrades, and the NYISO proposed to add a local transmission planning component and a regional economic planning component, and to extend the planning cycle from one year to two years. The June 18, 2008 filing submitted by NYISO and the NYTOs supplemented the NYISOs December 7 filing with tariff revisions governing cost allocation and cost recovery for regulated transmission reliability projects.

The Commission's October 16, 2008 order found that the tariff proposals in the December 7 and June 18 filings were substantially consistent with the planning directives set forth in Order Nos. 890 and 890-A, and conditionally accepted those proposals for filing subject to the submission of a compliance filing addressing certain issues. The FERC directed the NYISO to submit a compliance filing addressing the committee process, the manner in which stakeholders are able to replicate NYISO planning studies, the dispute resolution processes applicable to the planning process, cost allocations for economic upgrades, and metrics to be used for evaluating economic upgrades. NYISO submitted a partial compliance filing on January 14, 2009 and submitted the remainder of the required compliance items on May 19, 2009.

On March 31, 2009, the Commission issued an order on rehearing granting, in part, and denying, in part, rehearing of its October 16, 2008 order.[127] The March 31 order granted rehearing to state that the NYTOs and other developers have the burden to justify the justness and reasonableness of the rates they file in the section 205 filings contemplated by the NYISO planning proposal and not the NYISO. However, it denied the New York Regional Interconnect Inc.'s (NYRI) request for rehearing regarding the NYISO's proposed benefit metric and the supermajority voting procedure.

On April 29, NYRI filed a request for rehearing of the Commission's March 31, 2009 order and motion to reopen the record stating the Commission erred by not considering the 2008 NYISO White Paper titled *Transmission Expansion in New York State: A New York ISO White Paper* and concluding that it is not obliged to consider the anticompetitive effects the NYISO's supermajority voting rule. NYRI also filed a protest of NYISO's May 19 compliance filing arguing that, among other things, the procedures favor the interests of southeast NYTO shareholders over New York electricity consumers and lack transparency and provide obvious opportunities for abuse. In addition, NYRI filed a petition for review in the D.C. Circuit of the October 16, 2008 and March 31, 2009 Commission orders.[128] On September 16, 2009, the D.C. Circuit dismissed NYRI's petition for review as incurably premature in light of NYRI's pending request for rehearing before the FERC.

On October 15, 2009, the Commission issued an order on rehearing denying NYRI's request for rehearing of the Commission's March 31, 2009 order and dismissing the motion to reopen the record as moot.[129] The Commission noted that it ordinarily does not allow rehearing of an order denying rehearing unless the order denying rehearing modifies the core ruling of the original order. In this case, the Commission held that the FERC's order denying hearing did not modify its order accepting NYISO's proposed supermajority voting procedures.

127. *N.Y. Indep. Sys. Operator, Inc.*, 126 F.E.R.C. ¶ 61,320 (2009).

128. N.Y. Reg'l Interconnect, Inc. v. FERC, No. 09-1150 (D.C. Cir. dismissed Sept. 16, 2009).

129. *N.Y. Indep. Sys. Operator, Inc.*, 129 F.E.R.C. ¶ 61,045 (2009).

Additionally, the FERC stated that NYRI's rehearing request only reiterated its previous antitrust objections to the supermajority voting procedure. The Commission dismissed NYRI's motion to reopen the record because the White Paper is already in the record of the proceeding as an attachment to an NYRI filing made in February 2009.

On December 14, 2009, NYRI filed a petition for review in the D.C. Circuit of the October 16, 2008, March 31, 2009, and October 15, 2009 Commission orders.[130]

The New York ISO also implemented a deliverability standard in its facility interconnection procedures. This is addressed in Section IX.F. *infra*.

C. PJM Interconnection

1. Shifts in RTO Membership

During 2009, issues regarding the obligation of RTO members to pay legacy costs if they move from membership in one RTO to another continued to arise before the Commission. In review of requests to withdraw from an RTO, the Commission applied the standard of review established in *LG&E Withdrawal Order*:[131] satisfaction of the terms of applicable contractual obligations, and replacement arrangements that comply with Order Nos. 888 and 890 that are just, reasonable and not unduly discriminatory.

On January 29, 2009 the Commission issued an order allowing Duquesne Light Co. (Duquesne) to withdraw its previous request to withdraw from the PJM Interconnection, L.L.C. (PJM).[132] An agreement was reached that reduced Duquesne's capacity procurement costs under PJM's forward capacity market mechanism, thereby obviating the principal reason Duquesne had sought to move from PJM to the Midwest Independent System Operator, Inc. (Midwest ISO).[133]

During the course of the *Duquesne* proceeding, the Commission made a number of rulings with respect to the responsibility for costs in the event a transmission owner withdrew from PJM. In *Duquesne Light Co.*,[134] the Commission held that Duquesne would remain subject to costs incurred on its behalf under the PJM Consolidated Transmission Owners Agreement (TO Agreement) and capacity commitments under the Resource Reliability Agreement (RA Agreement) implementing PJM's Reliability Pricing Model (RPM) forward capacity market. While the Commission found that it would need further proceedings to determine whether Duquesne's plans would satisfy the TO Agreement, the Commission held with respect to the RA Agreement that Duquesne would remain subject to RPM charges for all auctions in which its load forecasts had been included.[135]

In ruling on the RA Agreement obligations, the Commission held that Duquesne's obligations to pay Locational Reliability Charges under PJM's RPM

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130. N.Y. Reg'l Interconnect, Inc. v. FERC, No. 09-1309 (D.C. Cir. Dec. 14, 2009).

131. 114 F.E.R.C. ¶ 61,282 at P 12 (2006), *order on reh'g*, 116 F.E.R.C. ¶ 61,020 (2006).

132. *Duquesne Light Co.*, 126 F.E.R.C. ¶ 61,074 (2009), *reh'g denied*, 127 F.E.R.C. ¶ 61,187 (2009).

133. 126 F.E.R.C. ¶ 61,074 at PP 7-10.

134. 122 F.E.R.C. ¶ 61,039 (2008).

135. *Id.* at P 6.

were fixed at the time Duquesne's loads were included by PJM in the forward capacity auctions, since PJM's obligation to pay the generators is fixed at the time of the auction.[136] The Commission required PJM to mitigate Duquesne's costs to the extent possible, but it rejected Duquesne's argument that it should be released from its obligation because PJM might be able to otherwise use the capacity it purchased on Duquesne's behalf.[137]

In *Midwest Independent Transmission System Operator, Inc.*,[138] the Commission interpreted the PJM Tariff to not require Duquesne to pay Transmission Enhancement Charges annually allocated under the PJM Tariff after Duquesne withdrew from PJM.[139] The Commission rejected arguments that Duquesne should be liable for a share of costs of any transmission expansion project approved while Duquesne was a member of PJM. The Commission held that PJM's Tariff requires that costs for certain high voltage projects included in PJM's Regional Transmission Expansion Plan (RTEP) are allocated on an annual basis to load zones in existence in PJM at the time of the allocation. Therefore, those costs are imposed on any new transmission owners that may have joined PJM at that time, but are not imposed on members that have departed in the meantime.[140]

On August 17, 2009, FirstEnergy Service Company (FirstEnergy) filed in Docket No. ER09-1589 seeking authority on behalf of its subsidiary, American Transmission Systems, Inc. (ATSI) to withdraw from the Midwest ISO and join PJM, but requesting a waiver of PJM's RTEP costs for facilities approved prior to its joining PJM. FirstEnergy argued that under the Midwest ISO Tariff it would be required to pay an exit fee equal to its share of costs for transmission expansion facilities approved while it was a member of the Midwest ISO and that it should not also be required to pay costs of PJM's transmission expansion facilities that were approved prior to its joining PJM.

On December 17, 2009, the Commission issued an order addressing FirstEnergy's requests and the numerous protests and comments from interested parties.[141] The Commission applied its *Duquesne* reading of PJM's Tariff and rejected FirstEnergy's claim that paying system-wide expansion costs under both tariffs would be unjust and unreasonable. The Commission said:

> Each of the PJM and Midwest ISO cost allocation methodologies has been accepted by the Commission as just and reasonable and not unduly discriminatory methodologies for allocating the costs among the members of each RTO. ATSI's voluntary choice to move from one RTO to another does not cause either of these methodologies to no longer be just and reasonable or not unduly discriminatory simply because each produces a different result. Transmission owners that seek to change RTOs should be prepared to assume the costs attributable to their decisions.[142]

136. *Id.* at PP 88-89.
137. *Id.* at PP 95-96.
138. 124 F.E.R.C. ¶ 61,219 (2008).
139. *Id.* at PP 162-167.
140. *Id.* at P 171.
141. *American Transmission Sys., Inc.*, 129 F.E.R.C. ¶ 61,249 (2009).
142. *Id.* at P 113.

The Commission suggested that the Transmission owners negotiate with FirstEnergy regarding the terms of ATSI's joining PJM, since there presumably would be benefits to the existing members from expansion of PJM's system.[143]

2. Scarcity Pricing

In Order No. 719, "the Commission established reforms to remove barriers to demand response by requiring RTOs and ISOs to reform their market rules" to more accurately reflect the value of energy during operating reserve shortages.[144] The Commission required compliance filings by the RTOs to implement these changes and to provide adequate support for proposed changes. PJM made its compliance filing under Order No. 719 on April 29, 2009 (as amended on May 1, 2009), and the Commission issued its Order on Compliance Filing on December 18, 2009.[145] The Commission acknowledged PJM's concern about its existing pricing mechanism that recognizes an energy shortage when it is occurring but does not result in price impacts sooner, during an operating reserve shortage, and granted PJM's request for an extension of time until April 1, 2010, to file an amended pricing mechanism that would recognize operating reserve shortages and be implemented by June 1, 2010, in time for the summer season.[146] The Commission required PJM to file a status report in 30 days regarding its ability to meet the April 1 and June 1 deadlines and any issues that could impede or delay its meeting those deadlines.

D. Midwest Independent Transmission System Operator

1. Revenue Sufficiency Guarantees

The Commission ruled on the Midwest ISO Tariff's provisions on Revenue Sufficiency Guarantees (RSG) in two FERC proceedings: (1) Docket No. ER09-411, concerning Tariff revisions the Midwest ISO proposed on December 12, 2008 to address, among other things, the Commission's rulings on the exclusion of RSG-exempt transactions from the denominator of the RSG rate; and (2) Docket Nos. ER06-493, ER09-961, ER09-963, and ER09-964, involving the suspension or termination of status of Market Participants due to failure to pay their share of resettlement adjustments arising from an RSG refund directive that was issued (but later withdrawn) in Docket Nos. EL07-86, *et al*. As of year-end 2009, other MISO filings regarding RSGs remained pending before the Commission.

On November 7, 2008, the FERC issued an order reiterating an earlier ruling that the RSG rate's denominator should include only transactions subject to RSG charges, so that there would be no "mismatch" with the numerator, and no shortfall in the recovery of RSG costs.[147] As an offshoot of the rulings regarding the exclusion of RSG-exempt transactions from the RSG rate, on December 12, 2008, the Midwest ISO filed in Docket No. ER09-411 Tariff changes involving the RSG exemption of deviations also exempt from

143. *Id.* at P 114.
144. *Order No. 719, supra* note 19, at P 194.
145. *PJM Interconnection, L.L.C.*, 129 F.E.R.C. ¶ 61,250 (2009).
146. *Id.* at PP 58, 62.
147. *Midwest Indep. Trans. Sys. Operator, Inc.*, 125 F.E.R.C. ¶ 61,156 at PP 28-30, 54-57 (2008).

Excessive/Deficient Energy Deployment Charges. On August 7, 2009, the Commission conditionally accepted clarifying and replacement provisions proposed by the December 12 Filing.[148] However, the August 7 order accepted and suspended, subject to refund and further order, the proposed provisions concerning RSG exemptions.[149] The Commission required the Midwest ISO to submit, within thirty days, a plan and timetable for the RSG Task Force's completion of an analysis of RSG exemption issues; and, based on the results of that analysis, to submit, within ninety days, either further support for the RSG exemptions or amendments to the December 12 Filing.[150] The December 7 remained pending as of the end of 2009.

Based on an RSG refund directive in the November 10, 2008, order in Docket Nos. EL07-86, *et al*., the Midwest ISO commenced suspension and/or termination proceedings in Docket Nos. ER06-493, ER09-961, ER09-963 and ER09-964 with respect to Market Participants that failed to pay their share of adjustments resulting from the Midwest ISO's ensuing resettlement of RSG charges. On May 6, 2009, however, the Commission withdrew that refund directive, and ordered the Midwest ISO to cease the resettlement.[151] On June 5, 2009, the Midwest ISO withdrew its suspension and termination filings.

2. Regional Expansion Criteria and Benefits

On July 9, 2009, the Midwest ISO and its Transmission Owners filed proposed revisions to the method for allocating the cost of Network Upgrades for generation interconnection projects meeting Regional Expansion Criteria and Benefits (RECB) standards. The filing parties' changes were proposed in response to the dramatic increase in the development of renewable resources in areas remote from their customers, and that they would ensure that more interconnection-related upgrade costs are allocated to the parties that cause, or benefit from, such costs. The proposed revisions are an interim step (Phase I) in the refinement of RECB cost allocation principles based on an ongoing stakeholder review.

The interim solution would: (1) eliminate the use of the Line Outage Distribution Factor (LODF) to allocate network upgrade costs to pricing zones; (2) increase costs assigned to the interconnecting generator; and (3) eliminate the requirement that the interconnecting generator demonstrate a one-year designation as a network resource or a one-year power purchase agreement to serve Midwest ISO load to be eligible for cost sharing. The filing parties stated that the long-term solution (Phase II), covering all types of network upgrades, would be filed in mid-2010.

On October 23, 2009, the Commission conditionally accepted the July 9, 2009 filing.[152] The Commission found that the interim approach reasonably resolves unintended impacts of the current cost allocation, and that there was a reasonable plan to develop a longer term solution.[153] The Commission required

148. *Midwest Indep. Trans. Sys. Operator, Inc.*, 128 F.E.R.C. ¶ 61,142 (2009).

149. *Id.* at P 50.

150. *Id.* at P 51.

151. *Ameren Serv. Co.*, 127 F.E.R.C. ¶ 61,121 (2009).

152. *Midwest Indep. Trans. Sys. Operator, Inc.*, 129 F.E.R.C. ¶ 61,060 (2009).

153. *Id.* at P 2.

a compliance filing to: (1) file Tariff revisions regarding the Phase II cost allocation methodology on or before July 15, 2010; and (2) reflect certain conforming Tariff changes.[154] The Commission also required reports on the status of the Phase II stakeholder process to be filed on November 20, 2009, February 26, 2010, and May 28, 2010.

E. Southwest Power Pool

1. "Balanced Portfolio" of Economic Upgrades

On August 15, 2008, Southwest Power Pool, Inc. (SPP) submitted amendments to its OATT to establish a process for including a "Balanced Portfolio"[155] of economic upgrades into the SPP Transmission Expansion Plan (STEP) and a regional postage stamp rate design for recovery of the costs of such upgrades. Additionally, SPP proposed to amend the provisions relating to the treatment of upgrades that result in the deferral or displacement of other upgrades. The FERC accepted SPP's proposed tariff revisions for filing effective October 17, 2008, as modified, and directed SPP to submit a compliance filing by December 15, 2008.[156] SPP submitted the required compliance filing on December 15, 2008,[157] prompting some parties to file protests.

On June 18, 2009, the FERC denied SPP's November 17, 2008, request for clarification, or in the alternative, rehearing of the October 16, 2008 order in this proceeding and accepted SPP's December 15, 2008 compliance filing, effective October 17, 2008, subject to a further compliance filing.[158] SPP submitted the required compliance filing on November 2, 2009. The matter was pending before the FERC at year end.

2. Aggregate Study Revisions

On April 24, 2009, SPP proposed tariff revisions[159] to further refine its Aggregate Transmission Service Study (ATSS) procedures, outlined in Attachment Z1 of the SPP Tariff, to improve its timeliness and effectiveness and reflect the policy recommendations of the Aggregate Study Improvement Task Force (ASITF).[160] In its filing, SPP proposed to eliminate the System Impact Study (the first study conducted in the ATSS process) for long-term service requests and instead provide in the Aggregate Facilities Study all of the information currently provided by the System Impact Study, with additional

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154. *Id.* at P 1.

155. Under the "Balanced Portfolio" approach, SPP evaluates the benefits of a group or portfolio of economic upgrades to be included in the STEP, rather than evaluating the benefits of individual upgrades on a project-by-project basis.

156. *Southwest Power Pool, Inc.*, 125 F.E.R.C. ¶ 61,054 (2008).

157. *Compliance Filing of Southwest Power Pool, Inc.*, Docket No. ER08-1419-001 (Dec. 15, 2008).

158. *Southwest Power Pool, Inc.*, 127 F.E.R.C. ¶ 61,271 (2009).

159. *See generally Filing of Revised Tariff Sheets to Modify the Transmission Request Aggregate Study Process of Southwest Power Pool, Inc.*, Docket No. ER08-1379-000 (Aug. 8, 2008) (proposing initial revisions on a temporary basis through the end of the open season closing January 31, 2010). The Commission accepted the tariff revisions on October 7, 2008. *Southwest Power Pool, Inc.*, 125 F.E.R.C. ¶ 61,022 at PP 2, 22 (2008).

160. The ASITF was created by the SPP Markets and Operations Policy Committee (MOPC) in 2007 to review the ATSS process and recommend policy changes to improve its timeliness and effectiveness.

information such as the actual revenue rate for the requested service, to assist customers in choosing whether to continue with the ATSS process or withdraw their request. In June 2009, the FERC issued a letter order accepting the tariff revisions, effective April 25, 2009, as requested.[161]

3. Wind Cost Allocation

In a companion filing made on April 24, 2009, SPP proposed to modify its regional transmission cost allocation methodology to incorporate in Attachment J of its Tariff separate cost allocation provisions for network upgrades associated with wind resources that qualify for Base Plan funding;[162] specific Base Plan criteria for wind resources; and revisions to the Safe Harbor Cost Limit for Base Plan upgrades to accommodate provisions specific to wind resources. Several parties moved to intervene in the proceeding, and a single protest and request for rejection was filed.[163]

On June 18, 2009, the FERC accepted SPP's wind cost allocation proposal for filing effective April 25, 2009, subject to conditions.[164] The FERC found as just and reasonable SPP's proposal to modify the Safe Harbor Cost Limit calculation to use requested capacity instead of net dependable capacity for wind resources and SPP's proposed cost allocation for network upgrades associated with wind resources that are designated to serve loads in another zone. Additionally, the FERC accepted, as an initial limit, SPP's proposal to limit Base Plan funding eligibility to network upgrade costs associated with wind resources with reserved capacity up to twenty percent of the customer's system peak responsibility. The FERC further directed that SPP study the operational challenges it identifies due to the integration of wind generating resources into its system and whether the twenty percent limit places transmission customers with smaller loads at a competitive disadvantage with customers serving larger loads with dedicated wind resources and report the results and other evidence to the FERC on or before June 18, 2010.[165]

F. California Independent System Operator Corporation

1. Implementation of Market Redesign and Technology Upgrade

On March 13, 2009, the FERC accepted a filing submitted by the California Independent System Operator Corporation (CAISO) in January 2009 to certify the readiness of the CAISO's Market Redesign and Technology Upgrade (MRTU) to go into effect on March 31, 2009.[166] The CAISO implemented MRTU on March 31 and it has been in effect since that date.

161. *Southwest Power Pool, Inc.*, Docket No. ER09-1042-000 (June 16, 2009).

162. Base Plan funding represents how SPP allocates costs for those upgrades included in and constructed pursuant to the STEP.

163. *See generally Motion to Intervene and Protest of Acciona Wind Energy USA, L.L.C.,* Docket No. ER09-1039-000 (May 15, 2009).

164. *Southwest Power Pool, Inc.*, 127 F.E.R.C. ¶ 61,283 (2009).

165. *Id.* at P 30.

166. *Cal. Indep. Sys. Operator Corp.*, 126 F.E.R.C. ¶ 61,221 (2009).

2. Acceleration of the CAISO's Payment Timeline

On September 17, 2009, the FERC conditionally accepted an amendment to the CAISO tariff submitted in June 2009 to accelerate the process by which the CAISO invoices and settles market transactions.[167] Pursuant to the FERC's order, the CAISO's payment acceleration program went into effect on November 1, 2009. On November 9, 2009, the FERC also accepted an amendment to the CAISO tariff submitted in September 2009 to modify the CAISO's payment acceleration program to resolve a settlement imbalance issue.[168]

The CAISO also modified its large generator interconnection procedures. This is addressed in Section IX.D. *infra*.

3. Reduction of the Maximum Unsecured Credit Limit

On November 19, 2009, the FERC accepted an amendment to the CAISO tariff submitted in September 2009 to modify the provisions in that tariff to reduce the maximum unsecured credit limit that may be granted to any CAISO market participant from $150 million to $50 million.[169]

G. WestConnect

In 2009, the FERC approved various requests and filings submitted by the WestConnect participants including tariff revisions addressing the regional transmission planning process of WestConnect's participating utilities (the Attachment K filings) filed in compliance with FERC's Order No. 890. In the Attachment K filings, the WestConnect participating utilities filed tariff revisions addressing issues related to coordination and transparency of regional planning among the WestConnect utilities and cost allocation issues associated with transmission planning. In 2009, WestConnect also initiated a point-to-point regional transmission service experiment in an effort to determine better ways of eliminating pancaked rates between its participating utilities (the Experiment). The Experiment was designed to promote access to coordinated transmission service from multiple transmission providers at a single rate and encourage greater and more efficient use of the electric transmission system, and reduce costs to customers. Under the Experiment, eligible transmission service customers are offered hourly non-firm transmission service on a non-discriminatory basis over two or more transmission systems of WestConnect's participating utilities. Transmission customers under this service pay for service at the highest rate for hourly non-firm transmission service as posted on the OASIS of the utilities involved in the transmission service. Transmission Customers also pay for losses, scheduling, system control, and dispatch charges. The Experiment will end after two years, unless the WestConnect participating members seek FERC authorization to extend the Experiment.

H. Entergy Independent Coordinator of Transmission

On April 24, 2006, the Commission accepted Entergy Services Inc.'s (Entergy) proposal for SPP to act as the Independent Coordinator of

167. *Cal. Indep. Sys. Operator Corp.*, 128 F.E.R.C. ¶ 61,265 (2009).
168. *Commission Letter Order*, Docket No. ER09-1744-000 (Nov. 9, 2009).
169. *Cal. Indep. Sys. Operator Corp.*, 129 F.E.R.C. ¶ 61,142 (2009).

Transmission (ICT) for the Entergy transmission system for a four-year term that will expire on November 17, 2010.[170] Over the course of 2009, several parties, including affected state commissions, have discussed the relative merits of how, and whether, to continue the ICT arrangement or how to integrate Entergy into the SPP RTO.[171] These discussions led to the formation of the Entergy Regional State Committee (E-RSC), a body consisting of the five retail regulators within Entergy's footprint. In addition to Entergy's compliance with Commission directives to report on the future of the ICT arrangement, the E-RSC will be making a recommendation to Entergy with regard to how to approach the ICT extension, or other alternatives.[172]

On November 17, 2009, Entergy submitted a compliance filing, focusing on two alternatives for going forward when the ICT contract expires – modifying the ICT arrangements or joining the SPP RTO.[173] An extension of the ICT arrangement (including those related to the role and authority of the E-RSC) for an interim period would, according to Entergy, allow additional time for consideration or implementation of the SPP RTO alternative.

IV. TRANSMISSION RATES

A. Cost-Based Rates

In *Idaho Power Company*,[174] the Commission addressed the question of how three pre-Order No. 888 transmission service agreements should be treated in calculating Idaho Power's post-Order No. 888 OATT rates. Idaho Power proposed that the revenues associated with the pre-Order No. 888 agreements be credited against the company's transmission costs, instead of allocating a share of the company's costs to the agreements.[175] The Commission ruled that the services under the pre-Order No. 888 agreements should be treated as firm transactions for ratemaking purposes, and therefore "should be included as part of the total firm load (i.e., cost-allocated in the denominator of the formula rate) rather than crediting the revenue that Idaho Power receives under the agreements against Idaho Power's total transmission revenue (i.e., revenue-credited in the numerator)."[176] The Commission also ruled that while the Commission may consider whether benefits provided by the customer to the service provider in exchange for discounted rates warrants the revenue credit approach, it was not necessary to consider that question here because there was no evidence that the pre-Order No. 888 agreements represented discounted transactions.[177] In

170. *Entergy Services, Inc.*, 115 F.E.R.C. ¶ 61,095 (2006).

171. *See, e.g.*, *Joint FERC and State Regulator Conference on the State of Transmission in the Entergy System*, Docket Nos. ER09-555-000 and ER05-1065-000 (June 24, 2009).

172. *See, e.g.*, *Entergy Services, Inc.*, *ICT Third Quarterly Report*, Docket No. ER05-1065-000, at 6 (Dec. 31, 2009).

173. *Entergy Services, Inc.*, *Entergy Compliance Filing*, Docket No. ER09-555 (Nov. 17, 2009).

174. *Idaho Power Co.*, 126 F.E.R.C. ¶ 61,044 (2009).

175. *Id.* at P 25.

176. *Id.* at PP 1, 83-84.

177. *Id.* at PP 155-56.

addition, the Commission ruled that Idaho Power should include the agreements' contract demands, rather than their peak demands, in the rate denominator.[178]

B. Incentive Rates

1. Public Service Electric and Gas Company[179]

Public Service Electric and Gas Company (PSEG) requested authorization from the FERC pursuant to FPA sections 205 and 219 for certain transmission rate incentives and modifications to PSEG's formula rate for transmission service for PSEG's portion of the proposed Mid-Atlantic Power Pathway Project (MAPP Project).[180] Specifically, PSEG sought a 150 basis point return on equity (ROE) adder, authority to recover 100% of all prudently-incurred development and construction costs if the MAPP Project is abandoned or cancelled for reasons beyond PSEG's control and authority to assign such incentives to an affiliate.[181] PSEG stated that it satisfies the rebuttable presumption of eligibility for incentives, established in Order No. 679,[182] that "the transmission project results from a fair and open regional planning process that considers and evaluates projects for reliability and/or congestion" because the requested incentives will only apply if PJM approves the MAPP Project including PSEG's portion.[183] The FERC held that PSEG satisfied the rebuttable presumption contingent on PJM's approval of PSEG's portion of the MAPP Project in the PJM Reliability Transmission Expansion Plan.[184] The FERC also held that sufficient nexus exists between the incentive rate requested and the investment PSEG will be required to make in the MAPP Project, which the FERC found is not a routine project.[185] With respect to the specific incentives requested, the FERC granted PSEG, contingent on approval of the project by PJM: (i) a 150 basis point ROE adder, finding that PSEG's overall ROE with the adder for the PSEG portion of the MAPP Project of 13.18% is within the range of reasonable returns and is just and reasonable;[186] (ii) authority to recover all prudently-incurred project costs if the PSEG portion of the MAPP Project is abandoned or cancelled for reasons beyond PSEG's control;[187] and (iii) authority to assign the

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178. *Id.* at PP 1, 211.

179. *Pub. Serv. Elec. and Gas Co.,* 126 F.E.R.C. ¶ 61,219 (2009).

180. *Id.* at P 1.

181. *Id.*

182. Order No. 679, *Promoting Transmission Investment Through Pricing Reform*, F.E.R.C. STATS. & REGS. ¶ 31,222, *order on reh'g*, 117 F.E.R.C. ¶ 61,345 (2006) (Order No. 679).

183. 126 F.E.R.C. ¶ 61,219 at PP 16, 19 (2009).

184. *Id*. at P 23.

185. *Id*. at P 48. The FERC encouraged:

> prospective owners of a transmission project for which multiple owners intend to request transmission rate incentives for their segments of the project – and where those multiple owners intend to rely on the scope, effects, and risks and challenges of the entire project as a basis for qualifying for such incentives – to submit a single joint filing requesting transmission rate incentives that are applicable to the entire project. *Id.* at P 55 (citations omitted).

186. *Id.* at P 62.

187. *Id.* at PP 65-66.

granted incentives to an affiliate, subject to a future section 205 filing to incorporate the incentives into such affiliate's rates.[188]

2. ITC Great Plains, L.L.C.[189]

ITC Great Plains, L.L.C. (ITC) requested authorization from the FERC pursuant to FPA sections 205 and 219 for certain transmission rate incentives for a series of transmission projects.[190] Specifically, ITC sought ROE adders of 50 basis points for participation in the SPP and 100 basis points for independence as a transco for the following projects: (1) two existing substations; (2) "approximately 170 miles of new transmission line [for the] Kansas" portion of the Kansas Electric Transmission Authority Project (KETA Project); (3) approximately 180 miles of new transmission line in Kansas, known as the Kansas V Plan; and (4) unidentified future projects that are part of the SPP transmission expansion plan or otherwise approved by SPP, high voltage facilities of 345 kV or higher and investments of at least $50 million.[191] In addition, for the three categories of new transmission projects, ITC sought authorization for an abandoned plant incentive, pre-construction, and start-up costs recovery in a regulatory asset, and 100% of construction work in progress (CWIP).[192] The FERC granted the requested ROE adders and found that the requested base rate of return of 10.66%, or 12.16% with the adders, is within the range of reasonableness.[193] However, the FERC found that ITC's proposed formula rates and rate protocols raised issues of material fact that could not be resolved based on the existing record and set such issues for settlement and hearing.[194]

With respect to the proposed non-ROE incentives, ITC stated that it is entitled to the rebuttable presumption that it meets the incentive eligibility requirements because the KETA Project and the Kansas V Plan are included in the 2008-2017 SPP STEP.[195] In the event that the FERC found that ITC is not entitled to the rebuttable presumption, ITC submitted studies to demonstrate that the projects meet the Order No. 679 eligibility requirements that such projects ensure reliability or reduce the cost of delivered power by reducing congestion.[196] The FERC held that ITC is not entitled to a rebuttable presumption that it meets the Order No. 679 eligibility requirements because the projects' inclusion in STEP does not reflect a determination by SPP that they are needed to address reliability or congestion.[197] However, the FERC held that ITC did demonstrate through the submitted studies that the KETA Project and the Kansas V Plan meet the Order No. 679 eligibility requirements.[198] In addition,

188. *Id.* at P 70.
189. *ITC Great Plains, L.L.C.*, 126 F.E.R.C. ¶ 61,223 (2009).
190. *Id*. at P 1.
191. *Id.* at PP 3-7.
192. *Id.* at P 7.
193. *Id.* at PP 92, 99.
194. *Id.* at P 110.
195. *Id.* at P 26.
196. *Id.* at PP 35-38.
197. *Id.* at P 34.
198. *Id.* at PP 42-43.

the FERC found that ITC demonstrated that there is a nexus between the risks of the KETA Project and Kansas V Plan and the requested incentives because, based on the scope, effects, risks, and challenges, the projects are not routine.[199] For the KETA Project and the Kansas V Plan, the FERC granted ITC authority to recover all prudently-incurred project costs if a project is abandoned for reasons outside of ITC's control,[200] authority to create regulatory assets,[201] and authority to include 100% of CWIP in rate base.[202] Finally, the FERC denied ITC's request for incentives for unidentified future projects because the FERC requires a specific showing justifying the requested incentives on a project-by-project basis.[203]

3. Pioneer Transmission, L.L.C.[204] [note: this heading missing from TOC]

Pioneer Transmission, L.L.C. (Pioneer) requested authorization from the FERC pursuant to FPA sections 205 and 219 for certain transmission rate incentives and to establish a formula rate for inclusion in the PJM and Midwest ISO tariffs for transmission service for a proposed 240-mile 765 kV transmission line in Indiana that will connect PJM and Midwest ISO.[205] Specifically, Pioneer sought: (1) an ROE of 13.5%, which reflects a base ROE of 11.0% plus ROE adders of 50 basis points for RTO membership, 50 basis points for the use of advanced transmission technology and 150 basis points for investment in new transmission; (2) authority to recover 100% of CWIP in rate base; (3) authority to recover 100% of prudently-incurred costs in the event that the project is abandoned for reasons outside of Pioneer's control; and (4) authority to establish a regulatory asset consisting of all project expenses that are not capitalized and included in CWIP prior to the date that Pioneer's proposed formula rate becomes effective.[206] Based on studies submitted by Pioneer, the FERC held that Pioneer demonstrated that its project meets the incentive eligibility requirements that the project enhance reliability and/or reduce the cost of delivered power by reducing congestion.[207] The FERC also found that sufficient nexus exists between the incentives requested and the risks and challenges Pioneer will face in developing the project because, based on the project's scope, effects, risks, and challenges, the project is not routine.[208]

With respect to the requested ROE, the FERC granted Pioneer an overall ROE of 12.54%, comprised of a 10.54% base return, plus ROE adders of 50 basis points for RTO participation and 150 basis points for investment in new transmission.[209] The FERC denied Pioneer's request for an additional 50 basis point ROE adder for advanced technology finding that "the 765 kV technologies

199. *Id.* at P 61.
200. *Id.* at P 69.
201. *Id.* at P 74.
202. *Id.* at P 81.
203. *Id.* at P 51.
204. *Pioneer Transmission, L.L.C.*, 126 F.E.R.C. ¶ 61,281 (2009).
205. *Id.* at PP 1-2.
206. *Id.* at PP 6-9.
207. *Id.* at P 41.
208. *Id.* at PP 47-48.
209. *Id.* at P 91.

and techniques proposed by Pioneer have been in use for many years . . . ."[210] In addition, the FERC found that Pioneer's proposed formula rates and rate protocols raised issues of material fact that could not be resolved based on the existing record and set such issues for settlement and hearing.[211] With respect to the non-ROE incentives, the FERC granted Pioneer authority to recover 100% of CWIP in rate base,[212] authority to recover all prudently-incurred project costs if the project is abandoned for reasons beyond Pioneer's control,[213] and authority to establish a regulatory asset consisting of all project expenses that are not capitalized and included in CWIP prior to the date that Pioneer's proposed formula rate becomes effective.[214]

4. Trans-Allegheny Interstate Line Company[215]

Trans-Allegheny Interstate Line Company (TrAILCo) requested authorization from the FERC pursuant to FPA section 205 to implement a 12.7% incentive ROE for the replacement of autotransformers and the upgrade of associated equipment at the Kammer Substation (Kammer Project).[216] TrAILCo stated, and the FERC found, that it is entitled to the rebuttable presumption that it meets the incentive eligibility requirements because the Kammer Project was approved by PJM and included as a baseline project in the PJM Regional Transmission Expansion Plan.[217] However, the FERC held that TrAILCo had "not demonstrated how the scope, effect and risks or challenges of the Kammer Project warrant an incentive ROE, and, therefore, TrAILCo does not meet the nexus test."[218] As such, the FERC denied TrAILCo's request for an incentive ROE for the Kammer Project.[219]

5. Green Power Express, L.P.[220]

Green Power Express, L.P. (Green Power) requested authorization from the FERC pursuant to FPA sections 205 and 219 for certain transmission rate incentives and a formula rate for its proposed 765 kV transmission network that will include approximately 3,000 miles of transmission lines in order to bring up to 12,000 MW of renewable energy in the Midwest to Midwestern load centers.[221] Specifically, Green Power requested: (1) recovery of prudently-incurred costs in the event that the project is abandoned for reasons outside of Green Power's control; (2) authority to create regulatory assets for start-up, development and pre-construction costs; (3) recovery of 100% of CWIP in rate base; "(4) a hypothetical capital structure of 60[%] equity and 40[%] debt" until

210. *Id.* at P 58.
211. *Id.* at P 110.
212. *Id.* at P 64.
213. *Id.* at P 75.
214. *Id.* at P 83.
215. *Trans-Allegheny Interstate Line Co.*, 126 F.E.R.C. ¶ 61,286 (2009).
216. *Id.* at P 1.
217. *Id.* at PP 13, 15.
218. *Id.* at P 25.
219. *Id.* at P 32.
220. *Green Power Express, L.P.*, 127 F.E.R.C. ¶ 61,031 (2009).
221. *Id.* at PP 1, 4.

any portion of the project is placed in service; and (5) an ROE of 12.38%, based on a base ROE of 10.78% plus 50 basis points for participating in an RTO, 100 basis points for independence and 10 basis points for the risks and challenges of the project.[222] Based on studies and an engineering affidavit submitted by Green Power, the FERC held that Green Power demonstrated that its proposed project meets the transmission incentive eligibility requirements because it will ensure reliability and reduce congestion.[223] The FERC also found that Green Power satisfied the requirement that there be a nexus between the incentives sought and the investment being made because the proposed project "is not routine by any measure," noting the size and cost of the project, jurisdictions involved and impact on the region.[224] The FERC granted each of Green Power's requested incentives and ROE,[225] but found that Green Power's proposed formula rate and rate protocols raised issues of material fact that could not be resolved based on the existing record and set those issues for settlement and hearing.[226]

6. Baltimore Gas and Electric Company[227]

Baltimore Gas and Electric Company (BG&E) requested authorization from the FERC pursuant to FPA section 205 to implement certain transmission rate incentives for its portion of the MAPP Project.[228] Specifically, BG&E sought a ROE adder of 150 basis points for new transmission construction and authority to recover 100% of prudently-incurred costs in the event that the MAPP Project is abandoned for reasons beyond BG&E's control.[229] BG&E stated, and the FERC found, that it is entitled to the rebuttable presumption that it meets the incentive eligibility requirements because the MAPP Project was included as a baseline project in the PJM Regional Transmission Expansion Plan.[230] The FERC also found that sufficient nexus exists between the incentives requested and the investment BG&E will make in the MAPP Project as the MAPP Project is not routine given its scope, effect, risks and challenges.[231] The FERC granted BG&E's requests for a 150 basis point ROE adder for new transmission construction for an overall ROE of 12.8%[232] and authority to recover 100% of prudently-incurred costs if the MAPP Project is abandoned for reasons beyond BG&E's control.[233]

7. Central Maine Power Company and Maine Public Service Company[234]

On November 17, 2008, the FERC granted Central Maine Power Company and Maine Public Service Company (the Maine Companies) certain transmission

222. *Id.* at PP 7-8.
223. *Id.* at PP 38-41.
224. *Id.* at P 46.
225. *Id.* at PP 50, 59-60, 65, 72, 80, 85-86, 92.
226. *Id.* at P 102.
227. *Baltimore Gas and Elec. Co.*, 127 F.E.R.C. ¶ 61,201 (2009).
228. *Id.* at P 1.
229. *Id.*
230. *Id.* at PP 22, 24.
231. *Id.* at PP 28, 35, 52.
232. *Id.* at P 46.
233. *Id.* at P 41.
234. *Cent. Maine Power Co. & Maine Pub. Serv. Co.*, 129 F.E.R.C. ¶ 61,153 (2009).

incentives pursuant to FPA section 219 for their proposed Maine Power Connection Project conditioned on ISO New England's approval of the project in its Regional System Plan as a Market Efficiency Upgrade and a subsequent showing by the Maine Companies that such designation satisfies the incentive eligibility requirement of section 219.[235] Several entities sought rehearing of the November Order and several entities filed a motion to lodge evidence that the Aroostook Wind Energy Project is discontinued.[236] The moving parties argued that because the primary purpose of the Maine Companies' proposed project was to connect the Aroostook Wind Energy Project to the grid in southern Maine evidence that the wind project has been discontinued is a material change in the facts that bears directly on the FERC's rationale for granting the transmission incentives.[237] The FERC granted the motion to lodge evidence and found that "[i]n light of the cancellation of the Aroostook Wind Energy Project, and also in light of the Maine Public Utilities Commission's subsequent dismissal of the CPCN proceeding, . . . [the Maine Companies' project], as described in the petition for declaratory order, has ceased to exist."[238] As such, the FERC dismissed the requests for rehearing, finding that such requests "have been overtaken by subsequent events."[239]

8. Green Energy Express, L.L.C.[240]

Green Energy Express, L.L.C. (Green Energy) requested authorization from the FERC pursuant to FPA section 219 for "certain transmission rate incentives for its proposed transmission project" in southern California comprised of approximately seventy miles of double circuit 500 kV transmission line, a new substation and a fast-acting shifter.[241] Specifically, Green Energy sought: "(1) deferred recovery of pre-commercial expenses" through the creation of a regulatory asset; "(2) inclusion of 100[%] of construction work in progress in rate base;" (3) recovery of project costs in the event it is abandoned for reasons beyond Green Energy's control; (4) a hypothetical capital structure of 50% equity and 50% debt until the project is placed in service; and (5) return on equity adders of 100 basis points for transco formation, 50 basis points for participation in an RTO and 50 basis points for the unique risks and challenges facing the project.[242] The Commission held that, despite the studies submitted by Green Energy, Green Energy had not demonstrated that its project will ensure reliability or reduce the price of delivered power by reducing congestion.[243] However, the FERC held that "because the CAISO's planning process may adequately consider the reliability and congestion-relieving impacts of the Project, the Commission will conditionally approve the incentives requested by

235. *Cent. Maine Power Co.*, 125 F.E.R.C. ¶ 61,182 at P 1 (2008).
236. 129 F.E.R.C. ¶ 61,153 at PP 7-8 (2009).
237. *Id.* at PP 8-9.
238. *Id.* at PP 14-15.
239. *Id.* at P 17.
240. *Green Energy Express, L.L.C.*, 129 F.E.R.C. ¶ 61,165 (2009).
241. *Id.* at PP 1, 3.
242. *Id.* at P 37.
243. *Id.* at P 27.

Green Energy."[244] The FERC directed Green Energy to file within thirty days after the CAISO's approval or disapproval of the project evidence of such determination as well as evidence that such approval demonstrates a finding that the project ensures reliability or reduces the cost of delivered power by reducing congestion.[245] The FERC also held that Green Energy met the requirements that there be a nexus between the incentives sought and the investment being made because the project is not routine in size, effects, lead-time, and jurisdictions involved.[246] The FERC granted each of Green Energy's requested incentives, subject to the later showing regarding the CAISO's approval of the project, and found that the total package of incentives requested are tailored to address the risks and challenges faced by Green Energy in developing the project.[247]

9. Citizens Energy Corporation[248]

Citizens Energy Corporation (Citizens) requested authorization from the FERC pursuant to FPA section 219 for certain transmission rate incentives for the portion of the proposed Sunrise Powerline Project located in Imperial Valley.[249] Specifically, Citizens sought authority to recover 100% of prudently-incurred costs if the project is cancelled "for reasons beyond Citizens' control[,] . . . a hypothetical capital structure of 50[%] debt and 50[%] equity and a 30-year levelized capital recovery approach."[250] Citizens stated, and the FERC found, that Citizens is entitled to the rebuttable presumption that it meets the incentive eligibility requirements because its "[p]roject [was] approved by the CAISO transmission planning process and received a certificate of public convenience and necessity from the CPUC."[251] The FERC also found that sufficient nexus exists between the incentives requested and the risks and challenges Citizens will face in developing the project because, based on the project's scope and purpose, the project is not routine.[252] The FERC granted each of Citizens' requested incentives.[253]

10. Southern California Edison Company[254]

Southern California Edison Company (SCE) requested authorization from the FERC pursuant to FPA section 219 for certain transmission rate incentives for its proposed transmission project in southern California comprised of construction of "a new substation and 35-miles of double-circuit 220 kV transmission line" and removal of thirty-five miles of existing transmission line.[255] Specifically, SCE sought authority to recover 100% of CWIP in rate

244. *Id.* at P 30.
245. *Id.*
246. *Id.* at P 35.
247. *Id.* at PP 38, 66.
248. *Citizens Energy Corp.*, 129 F.E.R.C. ¶ 61,242 (2009).
249. *Id.* at P 1.
250. *Id.*
251. *Id.* at P 16.
252. *Id.* at PP 17-18.
253. *Id.* at PP 19, 22-23.
254. *Southern California Edison Co.*, 129 F.E.R.C. ¶ 61,246 (2009).
255. *Id.* at PP 1-2.

base, 100% of prudently-incurred costs in the event that the project is abandoned for reasons beyond SCE's control, and a 150 basis point ROE adder.[256] In addition, SCE sought a declaration that the proposed "facilities [will] be network facilities eligible to be rolled into [SCE's] . . . transmission revenue requirement."[257] The Commission held that, despite the studies submitted by SCE, SCE had not demonstrated that its project will "[ensure] reliability or [reduce] the price of delivered power by reducing congestion."[258] However, the FERC held that "because the CAISO's . . . planning process may adequately consider the reliability and congestion-relieving impacts of the [project], the Commission will conditionally grant the incentives requested by [SCE]."[259] The FERC directed SCE to file within thirty days after the CAISO's approval or disapproval of the project evidence of such determination as well as evidence that such approval demonstrates a finding that the project ensures reliability or reduces the cost of delivered power by reducing congestion.[260] The FERC also held that SCE met the requirements that there be a nexus between the incentives sought and the investment being made because the project is not routine, based on its scope and effect and the risks and challenges it will face.[261] The FERC granted SCE's requested non-ROE incentives, i.e., 100% of CWIP in rate base and the abandoned plant incentive, but authorized only a 100 basis point ROE adder.[262] In addition, the FERC found that the project facilities will be network facilities.[263]

11. Otter Tail Power Company[264]

Otter Tail Power Company (Otter Tail) and Midwest ISO requested authorization from the FERC pursuant to FPA sections 205 and 219 for certain transmission rate incentives and modifications to Otter Tail's formula rate for three transmission expansion projects in Minnesota, North Dakota, and South Dakota.[265] Specifically, Otter Tail sought

> recovery of 100[%] of . . . [c]onstruction [w]ork in progress . . . in rate base, . . . recovery of 100[%] of prudently-incurred costs if a project is abandoned for reasons beyond Otter Tail's control and changes to its . . . formula rate using projected test period cost inputs with an annual true-up rather than . . . historic test period data.[266]

Otter Tail stated, and the FERC held, that Otter Tail is entitled to the rebuttable presumption that the projects meet the incentive eligibility requirements because the projects are part of a comprehensive regional planning initiative and have each received certificates of need from the Minnesota Public Utilities Commission.[267] The FERC also held that Otter Tail met the

256. *Id.* at P 5.
257. *Id.*
258. *Id.* at P 27.
259. *Id.* at P 28.
260. *Id.*
261. *Id.* at P 39.
262. *Id.* at PP 55, 67, 82.
263. *Id.* at P 89.
264. *Otter Tail Power Co.*, 129 F.E.R.C. ¶ 61,287 (2009).
265. *Id.* at PP 1, 4.
266. *Id.* at P 5.
267. *Id.* at P 27.

requirements "that there [be] a nexus between the incentive[s] sought and the investment being made" because the FERC had previously found that the projects present special risks.[268] The FERC granted Otter Tail's requested rate incentives and found that Otter Tail's proposed changes to its formula rate are just and reasonable, subject to certain modifications.[269]

C. Negotiated Rates

In 2009, the Commission refined its approach in evaluating merchant transmission owners' requests for negotiated rate authority by focusing on "four areas of concern: (1) the justness and reasonableness of rates; (2) the potential for undue discrimination; (3) the potential for undue preference; . . . and (4) regional reliability and operational efficiency requirements."[270] In *Chinook*, the Commission explained that its refined approach remains reflective of the policy established by prior Commission decisions, but is less rigid "and more flexible in addressing the financing realities and other issues faced by merchant transmission developers."[271]

"In determining whether negotiated rates are just and reasonable," the Commission explained in *Chinook* that it "first looks to whether the merchant transmission owner has assumed the full market risks for the cost of constructing a particular . . . project and is not building within the footprint of its own (or its affiliates') traditionally regulated transmission system."[272] The Commission further explained that it

> will also consider whether the merchant transmission owner or an affiliate already owns transmission facilities in the particular region of the project; what alternatives customers have; whether the merchant transmission owner is capable of erecting any barriers to entry and whether the merchant transmission owner would have any incentive to withhold capacity.[273]

"In order to prevent undue discrimination," the Commission explained that it would primarily look at "the terms and conditions of the merchant transmission developer's open season and . . . its OATT commitments."[274] With respect to undue preferences and affiliate concerns, the Commission clarified that it remains concerned of "potential for affiliate abuse . . . in situations where the merchant transmission owner is affiliated with either the anchor [tenant] participants in the open season and/or customers that subsequently take service on the . . . line."[275] If such affiliated relationships exist, the Commission made clear that it will apply a higher level of scrutiny.[276] With respect to regional reliability and operational efficiency, "merchant transmission [owners] will be required to comport with all applicable requirements . . . of [NERC] and any

268. *Id.* at PP 28-30.
269. *Id.* at PP 31, 33, 37-38.
270. *Chinook Power Transmission, L.L.C.*, 126 F.E.R.C. ¶ 61,134 (2009), *order on reh'g*, 128 F.E.R.C. ¶ 61,074 (2009).
271. *Id.* at P 37.
272. *Id.* at P 38.
273. *Id.*
274. *Id.* at P 40.
275. *Id.* at P 48.
276. *Id.* at PP 49-52.

regional reliability council."[277] The Commission also encouraged merchant transmission owners to participate in regional planning processes as their projects are underway.[278]

The Commission applied its refined analysis to several merchant transmission owner requests providing the opportunity to further explain its new approach as applied to specific facts. In *Chinook*, and a companion case *Zephyr Power Transmission, L.L.C.*,[279] the Commission conditionally approved both merchant transmission companies' request to charge negotiated rates for transmission rights on their respective projects.[280] Both projects are high voltage, DC transmission projects proposed to be built from Montana and Wyoming respectively to an area in close proximity to Las Vegas, Nevada.[281] Each entered into an agreement with a wind generation developer to become an "anchor customer" and to share a portion of the initial development costs and proposed to hold open seasons for the remaining capacity on the projects.[282] Neither Chinook nor Zephyr were affiliated with their anchor customers or with any transmission company in the area.[283] The Commission found that the projects satisfied the refined criteria and authorized negotiated rates.[284]

In *Wyoming Colorado Intertie, L.L.C.*,[285] the Commission was faced with many similar facts, a large proposed transmission line from Wyoming to Colorado proposed to interconnect new wind farms to interconnect to the grid and sell power into Colorado and other states. The project developer likewise had no relationships with its customers or local transmission companies and had no captive customers.[286] The Commission found, however, that the project was owned by LS Power – which the Commission noted is reported to be developing a new transmission intertie project that could interconnect with this project in future.[287] The Commission authorized the negotiated rates, but found that if the affiliated transmission project does proceed, the merchant transmission owner needs to promptly notify the FERC and address how they will continue to satisfy the just and reasonable rate requirement and affiliate concerns.[288]

In *Mountain States Transmission Intertie, L.L.C. and NorthWestern Corp.*,[289] the Commission rejected the merchant transmission owner's request for negotiated rate authority. The Commission stated that while it remains flexible, "[t]his flexibility . . . cannot compromise customer protections . . . ."[290] In Mountain States, the merchant transmission owner was a subsidiary of a

277. *Id.* at P 53.

278. *Id.*

279. *Chinook Power Transmission, L.L.C.*, 126 F.E.R.C. ¶ 61,134 (2009), *order on reh'g*, 128 F.E.R.C. 61,074 (2009).

280. 126 F.E.R.C. ¶ 61,134 at PP 54-55.

281. *Id.* at P 2.

282. 128 F.E.R.C. ¶ 61,074 at P 3.

283. 126 F.E.R.C. ¶ 61,134 at P4.

284. *Id.* at PP 54-55.

285. *Wyoming Colorado Intertie, L.L.C.*, 127 F.E.R.C. ¶ 61,125 (2009).

286. *Id.* at P 56.

287. *Id.*

288. *Id.*

289. *Mountain States Transmission Intertie & Nw. Corp., L.L.C.*, 127 F.E.R.C. ¶ 61,270 (2009).

290. *Id.* at P 58.

regulated transmission owner in the same region and was proposing to build a transmission project that was previously under study by its regulated transmission affiliate.[291] The Commission found that this relationship and the fact that the affiliated transmission company "played a substantial role in the preliminary stages of the . . . project" gave Mountain States "an undue preference not available to others . . . ."[292] "[T]hese concerns about the affiliate relationship," the Commission found, "[were] further exacerbated by the lack of an independent operator such as an RTO/ISO."[293] As a result, the Commission found that the merchant transmission owner had not demonstrated that its proposed negotiated rates would be just and reasonable.[294] "However," the Commission stated that there was "ample opportunity to accomplish many of [the same] objectives" of the project "and construct a project . . . on a cost of service basis [with] appropriate tariff waivers."[295]

V. CORPORATE ACTIVITIES

A. Mergers/Acquisitions

1. EDF

In December of 2008 Constellation Energy Group, Inc. (Constellation Energy), Constellation Nuclear Group, E.D.F. International S.A. (EDF International), and EDF Development, Inc. (EDF Development), executed a Master Agreement under which

> EDF Development [would] acquire a 49.99 percent ownership interest in [Constellation's] nuclear generation and operation business for $4.5 billion; [provide] a $1 billion up-front cash investment in Constellation Energy in the form of non-voting nonconvertible cumulative preferred stock; . . . and provide Constellation Energy with additional liquidity support of up to $2 billion through put options under the Master Agreement, which will remain in effect until the end of 2010.[296]

The put options provide Constellation Energy Group with the option, but not the obligation, to sell its ownership interests in various non-nuclear generating plants and certain associated jurisdictional assets to EDF Development.[297]

"Along with the Master Agreement, Constellation Energy and EDF International executed an Amended and Restated Investor Agreement that provided EDF International with the right to nominate one director to Constellation Energy's board following the proposed transaction, expanding the board from 12 to 13 directors."[298] Additionally, EDF requested "approval of a subsequent assignment of its rights under the Master Agreement to an affiliate, [assuming] the assignment does not [depart] from the facts the Commission

291. *Id.* at P 3.

292. *Id.* at P 61.

293. *Id.* at P 64.

294. *Id.* at P 65.

295. *Id.* at P 58.

296. *EDF Dev. Constellation Energy Group & Handsome Lake Energy*, 126 F.E.R.C. ¶ 61,140 at P 25 (2009).

297. *Id.* at P 26.

298. *Id.* at P 25.

relied [on] in approving the . . . transaction."[299] All the parties involved stated "that EDF International [would] not have a controlling interest in Constellation Energy because its interest is less than 10 percent and its ability to appoint less than 10 percent of the members of Constellation Energy's board . . . ."[300] The Commission found that there would be no adverse impact on regulation, rates or competition and approved the transaction on February 19, 2009.[301]

2. MACH Gen, L.L.C.

MACH Gen, L.L.C., and several other applicants, filed an application with the Commission requesting the Commission to grant "authorization for an indirect disposition of jurisdictional facilities" for a three-year period, with conditions, "as a result of the proposed acquisition of up to 40 percent of the equity interests in MACH Gen by funds under the management of SVP."[302] SVP stated in its application "that it is a holding company solely with respect to exempt wholesale generators qualifying facilities or foreign utility companies."[303] SVP and several of the funds under its management are holding companies under section 203(a)(2) of the FPA because "it manages the funds that hold interests in holding companies that, in turn, own generating companies . . . ."[304]

"The proposed transaction involve[d] the transfer . . . of equity interest . . . in MACH Gen by current and future owners . . . to funds managed by SVP."[305] Therefore, "SVP [sought] authorization to acquire additional ownership interests in MACH Gen . . . with a cap on SVP's total holdings of 40 percent."[306] SVP stated in its application that "it would not exercise any . . . control over day-to-day operations of MACH Gen and" more specifically, "any decision making over the day-to-day sales of electric energy . . . ."[307]

The Commission found "that SVP's acquisition of up to 40 percent of MACH Gen's equity interest . . . and SVP's ability to nominate individuals to MACH Gen's Board of Directors . . . evidences SVP['s] . . . ability to take action to control MACH Gen."[308] Therefore, the Commission authorized the transaction based on the conditions that would limit its ability to exercise control, such as not allowing SVP to increase its holdings without prior Commission authorization.[309] Further, the Commission required SVP to report to the Commission at the end every quarter its level of holdings "and . . . its continued compliance with the conditions . . . ."[310]

299. *Id.* at P 46.
300. *Id.* at P 25.
301. *Id.* at PP 1, 46.
302. *MACH Gen, L.L.C.*, 127 F.E.R.C. ¶ 61,127 at P 1 (2009).
303. *Id.*
304. *Id.* at note 2.
305. *Id.* at P 11.
306. *Id.*
307. *Id.*
308. *Id.* at P 36.
309. *Id.* at P 37.
310. *Id.*

Aside from the market issues addressed by the conditions stated in the order the Commission found that there would be no adverse impact on regulation,[311] and rates,[312] and approved the transaction, under section 203, on May 8, 2009.[313]

3. ALLETE

"ALLETE . . . filed an application with the Commission for authorization, under section 203 . . . to acquire transmission facilities from Square Butte Electric Cooperative . . . ."[314] "Under the [p]roposed [t]ransaction . . . ALLETE acquire[d] an existing 465 mile, 250 kV high-voltage direct current (HVDC) transmission line running from Square Butte's substation in Center, North Dakota to ALLETE's Arrowhead substation near Duluth, Minnesota . . . ."[315] Additionally, ALLETE acquired "all appurtenant HVDC facilities in the Square Butte Substation, certain alternating current facilities on the eastern side of the Square Butte Substation, Square Butte's assets in the Arrowhead Substation," associated real property interests and easements, interconnection facilities, books "and records, transmission tariffs, transmission agreements, interconnection agreements and transmission and interconnection requests associated therewith . . . ."[316]

"ALLETE and Minnkota Electric Cooperative . . . are the only two customers that take transmission service from Square Butte . . ." and the proposed acquisition was "part of restructuring the overall relationship among ALLETE, Square Butte, and Minnkota."[317] "ALLETE and Minnkota each purchase 50 percent of the output from Square Butte's Young 2."[318] "Under ALLETE's restructuring arrangement, it will gradually phase out its power purchases from Young 2 and replace that power with wind energy produced in North Dakota."[319]

The Commission found that there would be no adverse impact on regulation,[320] rates,[321] or competition,[322] and approved the transaction on November 24, 2009.[323] The Commission did note that this transaction would

> result in [a] rate increase for ALLETE's and Minnkota's customers [but that] [a]pplicant[s] explain[ed] that the rate increase is due to the HVDC [f]acilities' change in ownership from a cooperative to a public utility, and, [therefore,] ALLETE must recover . . . taxes and a return on equity related to those facilities[,]

311. *Id.* at P 46.
312. *Id.* at P 44.
313. *Id.* at PP 1-2.
314. *ALLETE, Inc.*, 129 F.E.R.C. ¶ 61,174 (2009).
315. *Id.* at P 1.
316. *Id.*
317. *Id.* at P 10.
318. *Id.*
319. *Id.*
320. *Id.* at P 22.
321. *Id.* at P 20.
322. *Id.* at P 16.
323. *See generally* 129 F.E.R.C. ¶ 61,174.

among other items.[324] Further, the Commission noted a benefit to this transaction is that the "Midwest ISO will be able to expand its scope over the HVDC [f]acilities by providing transmission service and ensur[ing] reliability."[325]

4. Exelon Corp.

On May 21, 2009, the Commission issued an Order Authorizing Merger and Acquisition of Jurisdictional Facilities in *Exelon Corp.*,[326] applying its Merger Policy Statement to review and approve the application.[327] The application was based upon a so-called "hostile take over" tender offer by Exelon Corporation of NRG Energy shares that was opposed by the NRG management.[328] Citing *Kansas City Power & Light*,[329] the Commission stated that it considered merger applications as it found them and that the fact that the proposed acquisition was not agreed to by both parties did not preclude its consideration of the application.[330] The Commission found Exelon's filed SEC Form S-4 to be a satisfactory surrogate for the otherwise required contracts since it "describes in detail the terms and conditions of [the] tender offer to NRG's shareholders and includes the form of documentation used in the exchange of shares."[331] The Commission found that Exelon's proposal satisfied the standards of review in the Merger Policy Statement.[332] On July 28, 2009, however, Exelon informed the Commission that it was terminating its offer to purchase NRG shares so the transaction would not be consummated.[333] The Commission has not acted on a motion to vacate the order authorizing the merger filed by Public Citizen's Energy Program on August 10, 2009.

B. Corporate Reorganizations

In *Cinergy Corp.*,[334] the FERC addressed issues pertaining to a proposed spin-off of generation assets from a traditional utility, Duke Energy Ohio (Duke Ohio), to several to-be-formed affiliates. The principle issues in the case had to do with the potential impact of the spin-off on retail ratepayers.[335] The activity

324. *Id.*

325. *Id.*

326. 127 F.E.R.C. ¶ 61,161 (2009).

327. *See, e.g.*, Order No. 592, *Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement*, F.E.R.C. STATS. & REGS. ¶ 31,044 (1996), *reconsideration denied*, Order No. 592-A, 79 F.E.R.C. ¶ 61,321 (1997) (Merger Policy Statement). *See also FPA Section 203 Supplemental Policy Statement*, F.E.R.C. STATS. & REGS. ¶ 31,253 (2007) (Supplemental Policy Statement), *order on clarification and reconsideration*, 122 F.E.R.C. ¶ 61,157 (2008). *See also* Order No. 642, *Revised Filing Requirements Under Part 33 of the Commission's Regulations*, F.E.R.C. STATS. & REGS. ¶ 31,111 (2000), *order on reh'g*, Order No. 642-A, 94 F.E.R.C. ¶ 61,289 (2001). *See also* Order No. 669, *Transactions Subject to FPA Section 203*, F.E.R.C. STATS. & REGS. ¶ 31,200 (2006), *order on reh'g*, Order No. 669-A, F.E.R.C. STATS. & REGS. ¶ 31,214, *order on reh'g*, Order No. 669-B, F.E.R.C. STATS. & REGS. ¶ 31,225 (2006).

328. 127 F.E.R.C. ¶ 61,161 at PP 1, 27-28, 95.

329. 53 F.E.R.C. ¶ 61,097, at 61,283-84 (1990) (rejecting argument that the application was part of a negotiating strategy and therefore should not be considered).

330. 127 F.E.R.C. ¶ 61,161 at P 25.

331. *Id.*

332. *Id.* at PP 93, 102, 105, 123, 126.

333. *Exelon Corp.*, 130 F.E.R.C. ¶ 61,095 at P 2 (2010).

334. *Cinergy Corp.*, 126 F.E.R.C. ¶ 61,146 (2009).

335. *Id.* at P 39.

in the FERC docket played out against a state regulatory backdrop that included revisions to Ohio law to give the Ohio Commission the authority to review the transaction.[336] At the request of the Applicants, the FERC delayed ruling in the case until after Ohio had approved the transaction.[337] At that point, the FERC deemed issues raised in protests regarding impact on state regulation to be moot.[338] The FERC accepted the Applicants' arguments that ratepayers would be protected because the Applicants offered a hold harmless commitment for customers under certain wholesale cost-based tariffs, including transmission and ancillary services customers, and because the Ohio Commission had approved and modified retail rates after taking the transaction into account.[339]

With respect to cross-subsidization concerns, the FERC generally accepted the Applicants' assertion that ratepayers would be protected by a combination of (1) retail choice in Ohio, which allows ratepayers to choose an alternative provider if rates are too high, and (2) commitments not to include generation costs in the transmission or distribution component of retail rates.[340] However, the FERC conditioned its approval on requirements that (1) Duke Ohio "not pay taxes associated with the transaction," "(2) all acquisition premiums related to generating assets being transferred . . . be removed from Duke Ohio's books," and (3) any debt "being transferred . . . be transferred . . . before Duke Ohio submitted its final accounting entry."[341]

Finally, the FERC granted the Applicants' request to confirm that the transaction, which would involve distribution by Duke Ohio of the shares in the newly formed companies to its parent Cinergy Corp., was not barred by FPA section 305(a), notwithstanding that the transaction would result in a distribution in excess of retained earnings.[342] The FERC found that there was no indication that the distribution would be excessive or preferential, and that due to the internal nature of the transaction shareholders would not be harmed because the same shareholders would have the same ownership interests before and after the transaction.[343] However, the FERC "condition[ed its] finding on Duke Ohio complying with its commitment to maintain a minimum equity to total capital ratio of 30 percent and to retain an amount of debt that is within the range that will accommodate preservation of Duke Ohio's [then-]current credit ratings."[344]

C. Blanket Authorizations

On June 26, 2009, the FERC granted a modification to a 2007 order[345] granting blanket authorizations for Ecofin Holdings, Ltd., on behalf of itself and its subsidiaries, for a period of three years for transactions involving the

336. *Id.* at P 38.
337. *Id.*
338. *Id.*
339. *Id.* at PP 45-46.
340. *Id.* at PP 47-51, 56.
341. *Id.* at PP 56-58.
342. *Id.* at PP 61-65.
343. *Id.* at PP 67-70.
344. *Id.* at P 69.
345. *Ecofin Holdings, Ltd.*, 120 F.E.R.C. ¶ 61,189 (2007).

acquisition and disposition of certain U.S. electric utility company securities.[346] The modified proposal sought an extension of the blanket authorization to include two additional subsidiaries.

On June 4, 2009, the FERC granted, on rehearing, Franklin Resources, Inc.'s request for blanket authorization, for a period of three years, for itself and certain of its subsidiaries, to acquire certain voting securities in U.S. electric company securities.[347] Franklin Resources sought rehearing to clarify certain obligations and ongoing reporting requirements.

VI. RESOLUTION OF 2000-2001 WESTERN ELECTRICITY MARKETS ISSUES

The FERC issued a number of Orders in 2009 as it continued to wind down enforcement and refund proceedings respecting the 2000-2001 California energy crisis. As described in detail elsewhere, the Commission initiated four principal proceedings in 2003 to review generator market conduct and determine if refunds, profit disgorgement, contract reformation, or other relief to end-users was appropriate.[348] Most generator specific proceedings ended by settlement and the FERC has asserted that over $6 billion has been returned to ratepayers.[349] In 2009, the FERC approved an additional settlement to distribute an additional $16.4 million held by it as the result of payments in connection with the above proceedings amongst affected wholesale customers, approved seven additional settlements between California Wholesale Customers Generators providing for further returns to customers of over $100 million, permitted several California municipalities to join previously approved settlements and denied several rehearing requests from prior orders approving settlements.[350] In the remand proceeding from *State of California ex rel. Lockyer v. FERC*,[351] in which the Court held that the FERC had authority to order refunds from market determined rates, it again denied the rehearing request of the California parties that evidence of misconduct other than that limited to improper or failure to file quarterly reports be permitted.[352] Evidentiary examination of these reports and whether they contributed to the ability of generators to manipulate the market continues. Also, in May, California Attorney General Edmund G. Brown Jr. filed an

346. *Ecofin Holdings, Ltd.*, 127 F.E.R.C. ¶ 62,244 (2009).

347. *Franklin Resources, Inc.*, 126 F.E.R.C. ¶ 61,250 (2009), *order on reh'g*, 127 F.E.R.C. ¶ 61,224 (2009).

348. *See, e.g.*, Walter R. Hall, HISTORY, OBJECTIVES AND MECHANICS OF COMPETITIVE ELECTRICITY MARKETS IN CAPTURING THE POWER OF ELECTRIC RESTRUCTURING at 42-45 (J. Miranda ed., 2009); Special Committee on Restructuring of the Electric Industry, *2003 Annual Report*, AMERICAN BAR ASS'N SECTION OF ENV'T, ENERGY & RESOURCES, THE YEAR IN REVIEW 2003 at 351-353 (2004); Special Committee on Restructuring of the Electric Industry, *2004 Annual Report*, AMERICAN BAR ASS'N SECTION OF ENV'T, ENERGY & RESOURCES, THE YEAR IN REVIEW 2004 at 346 (2005).

349. FERC, THE COMMISSION'S RESPONSE TO THE CALIFORNIA ELECTRICITY CRISIS AND TIMELINE FOR DISTRIBUTION OF REFUNDS (2005), *available at* http://www.ferc.gov/legal/staff-reports/comm-response.pdf.

350. *See, e.g., Duke Energy Trading & Mktg., L.L.C.*, 125 F.E.R.C. ¶ 61,345 (2008), *order on reh'g*, 126 F.E.R.C. ¶ 61,234 (2009); *San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Servs.*, 128 F.E.R.C. ¶ 61,256-259 (2009); *San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Servs.*, 128 F.E.R.C. ¶ 61,002 (2009); *San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Servs.*, 126 F.E.R.C. ¶ 61,007, 61,288 (2009); *Arizona Pub. Serv. Co.*, 125 F.E.R.C. ¶ 61,177 (2009); *Aquila Merch. Servs.*, 127 F.E.R.C. ¶ 61,218 (2009).

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

352. *California ex rel. Lockyer v. B.C. Power Exch. Corp.*, 129 F.E.R.C. ¶ 61,276 (2009).

additional complaint raising the broader market manipulation claims not permitted in the remand proceeding as to eighteen parties who had not yet settled with the California Parties. This complaint remains pending.[353] Finally, granting rehearing, the FERC reinstated an ALJ Initial Decision which it had vacated as moot after a settlement was reached in the proceeding. This decision concluded that Enron had violated its market-based rate authority and engaged in improper gaming and anomalous market behavior in the California markets of 2000-2001.[354]

VII. ENFORCEMENT

A. Policy Matters

The December 17, 2009, Commission order in Docket No. PL10-2 authorizes the secretary of the Commission, upon authorization of the Director of the Office of Enforcement, to issue a "Staff's Preliminary Notice of Violations" (Notice of Violations) after the subject of the investigation has had an opportunity to respond to the Commission staff's preliminary findings letter.[355] This order modifies the current procedures by permitting the Office of Enforcement to provide the public with details of the investigation earlier in the process than previously permitted – public disclosure usually did not occur until a settlement agreement was reached between the subject and the Office of Enforcement or the Commission issued an order to show cause.

Under the new procedures, as the Office of Enforcement completes its fact-finding process, it may make a preliminary determination that the subject has violated one or more Commission requirements. Upon making such a determination, the Office of Enforcement will send the subject a letter outlining the basis for the preliminary determination. Once the subject has had an opportunity to respond to staff's preliminary findings letter, the Director of the Office of Enforcement is authorized to direct the Secretary of the FERC to issue a Notice of Violations, identifying the entity under investigation and the alleged violations.

In addition, in a related action in Docket No. PL10-1, the Commission formalized a process by which the Office of Enforcement would provide exculpatory evidence (evidence that may be favorable to a subject of an investigation or respondent in an enforcement proceeding) to subjects of its investigations and respondents in administrative enforcement proceedings.[356]

B. Investigations

The following notable electric matters were handled by the Office of Enforcement's Division of Investigations in 2009:

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353. California ex rel. Brown v. Powerex Corp., Docket No. EL09-56-000 (May 22, 2009), *available at* http://www.ferc.gov/docs-filing/elibrary.asp.

354. *Enron Power Mktg., Inc.*, 126 F.E.R.C. ¶ 61,230 (2009).

355. *Enforcement of Statutes, Regulations, and Orders*, 129 F.E.R.C. ¶ 61,247 (2009).

356. *Enforcement of Statutes, Regulations, and Orders*, 129 F.E.R.C. ¶ 61,248 (2009).

1. Tower Research

In December 2007, PJM declared a major default by one of its members, Power Edge, L.L.C. (Power Edge), the costs of which would be socialized among other PJM members. Power Edge was an affiliate of Tower Research Capital, L.L.C. (Tower) and other companies in a family of hedge funds. Power Edge's default initiated a series of proceedings both before the Commission and in the courts between PJM and Tower. Enforcement staff opened a non-public investigation to explore allegations of manipulation in PJM's day-ahead and Financial Transmission Rights (FTR) markets. In the first phase of its investigation, staff examined whether Tower entities perpetrated a fraud upon PJM by entering into coordinated, offsetting positions in the market for FTRs by concentrating high-risk or losing positions in Power Edge, and deliberately causing Power Edge to default on its obligations, while holding profitable positions through other affiliates. Staff also examined whether Tower deliberately undercapitalized Power Edge. Office of Enforcement's Division of Investigations staff concluded that the evidence did not support the allegations, but that Tower supplied additional capital to Power Edge to try and prevent its collapse, and that Power Edge's FTR positions became unprofitable because of abnormal weather and transmission outages during the second half of 2007. While certain issues involving allegations of manipulation of PJM's FTR market remain under investigation, the Commission issued an order denying PJM's complaint with respect to the corporate fraud issues and released Enforcement staff's report.[357]

2. Lake Erie Loop Flow

In 2009, the Office of Enforcement's Division of Investigations staff concluded a non-public investigation into allegations of market manipulation in connection with Lake Erie loop flows.[358] The investigation began in May 2008, when the Market Monitoring and Performance Department of the NYISO referred allegations of market manipulation to Enforcement. The issues revolved around whether market participants engaged in manipulation with regard to inter-control area transactions that unlawfully exploited a "seam" in the pricing methods used by the NYISO, PJM, the Midwest ISO, and Ontario's Independent Electricity System Operator. Because there are no transmission lines under or over Lake Erie, electricity flows are split with a portion of power flowing clockwise and a portion flowing counterclockwise around the lake.

After extensive discovery, staff determined that the market participants involved in the investigation did not commit any tariff violations, were openly responding to organized market price signals, were not artificially affecting congestion in order to raise prices, and did not have the requisite scienter to commit market manipulation. In light of the significance of the issues raised and the impact on the RTOs in the area – including the NYISO, PJM, MISO, and the Independent Electricity System Operator – the Commission authorized the

357. *PJM Interconnection, L.L.C. v. Accord Energy, L.L.C.*, 127 F.E.R.C. ¶ 61,007 (2009), *reh'g denied*, 129 F.E.R.C. ¶ 61,010 (2009).

358. Loop flow refers to physical flows that differ from scheduled flows, which can cause congestion on transmission lines that can affect market prices of electricity.

public disclosure of the Division of Investigations' staff report, and adopted staff's findings and conclusions.[359]

3. Florida Blackout

The Office of Enforcement's Division of Investigations staff, coordinating with staff in other Commission offices, completed its investigation into the causes of the 2008 Florida blackout.[360] The event, which occurred on February 26, 2008, led to the loss of twenty-two transmission lines, 4,300 MW of generation, and 3,650 MW of customer service or load. The event originated at the Flagami Substation on the Florida Power and Light Company (FPL) system when a field engineer was diagnosing a piece of transmission equipment that had previously malfunctioned. In September 2009, Enforcement, NERC, and FPL signed a Stipulation and Consent Agreement relating to alleged violations of Reliability Standards committed by FPL. The settlement was approved by the Commission on October 8, 2009.[361] Under the settlement, FPL was required to pay a $25 million civil penalty. FPL is also adding significant additional protection redundancy at several transmission stations and has committed to undertake numerous specific reliability enhancement measures. These measures include: enhancing its compliance program; enhancing training and certification requirements for operating employees; improving its frequency response; updating emergency operating procedures; providing additional staffing for Bulk Electric System analysis; and ensuring that specified equipment is properly inspected and maintained. FPL has also agreed to make quarterly progress reports to Enforcement and NERC and conduct an independent audit after one year following the Agreement to ensure compliance with the Agreement.

C. Audits

1. Southwest Power Pool

In Docket No. PA08-2, the FERC initiated an audit to address SPP responsibilities as both a Regional Entity (RE) and an RTO. The audit primarily evaluated whether SPP was operating in compliance during certain months in 2007 with: (1) the SPP Bylaws;[362] (2) the Delegation Agreement between the North American Electric Reliability Corporation and SPP[363] and the conditions included in the Delegation Order; (3) the SPP Membership Agreement;[364] and (4) the transmission provider obligations described in the SPP OATT.[365]

a. SPP (Regional Entity)

On January 15, 2009, the FERC approved an audit report that contained staff's findings and recommendations with respect to SPP's compliance with its

359. *New York Indep. Sys. Operator, Inc.*, 128 F.E.R.C. ¶ 61,049 (2009).

360. *2008 Florida Blackout*, 122 F.E.R.C. ¶ 61,244 (2008).

361. *Florida Blackout*, 129 F.E.R.C. ¶ 61,016 (2009).

362. *Southwest Power Pool, Inc.*, 108 F.E.R.C. ¶ 61,003 (2004); *North American Elec. Reliability Council*, 119 F.E.R.C. ¶ 61,060 (2007), *order on reh'g*, 120 F.E.R.C. ¶ 61,260 (2007).

363. *North American Elec. Reliability Council*, 119 F.E.R.C. ¶ 61,060.

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

365. *Southwest Power Pool, Inc.*, 117 F.E.R.C. ¶ 61,139 (2006).

responsibilities as an RE.[366] The audit report concluded that "SPP did not have an adequate separation between its RTO and RE functions during the audit period."[367] Specifically, Office of Enforcement (OE) staff found three main areas of concern:

> (1) SPP (RE) did not operate with sufficient independence of SPP (RTO); (2) SPP (RE) trustees' oversight of the SPP (RE) functions could be improved to prevent conflicts of interest and to ensure the RE's independence; and (3) the SPP (RE)'s implementation of certain aspects of SPP's Compliance Monitoring and Enforcement Plan (CMEP) was inadequate.[368]

Among other staff recommended corrective action agreed to SPP, the FERC noted that SPP agreed to "hire a Regional Manager dedicated solely to SPP (RE) and eliminate all reporting relationships between SPP (RE) and SPP (RTO) employees."[369]

b. SPP (RTO)

On May 6, 2009, the FERC approved an audit report that contained staff's findings and recommendations with respect to SPP RTO operations.[370]

> The [audit] report found that SPP did not (1) notify its customers of its inability to complete System Impact Studies and Facilities Studies before the deadlines specified in its OATT; (2) conduct any audits of participants in its Energy Imbalance Service Market to determine their compliance with data retention requirements, as required by its OATT; (3) follow its travel policy for the use of chartered or private aircraft [and costs charged to the SPP for travel]; and (4) adopt Standards of Conduct governing non-monetary gratuities and review potential conflicts of interest affecting a Board of Directors member who is also affiliated with a law firm doing business with public utilities operating in the SPP service territory and a member of a company that insures nuclear power plants operated by SPP members.[371]

Of note, the FERC expressed concern that "although SPP's energy imbalance market has been in operation since February 1, 2007, SPP had no plan or schedule in place to audit market participants' data retention requirements."[372] The audit recommends, and the FERC approved, several corrective actions that "are intended to assure that SPP's future operations comply with its OATT, travel policy, and Standards of Conduct."[373]

2. New York Independent System Operator

On May 6, 2009, the FERC approved staff's findings and recommendations in an audit report that addressed NYISO's compliance with a selected set of its responsibilities under (1) the NYISO Agreement,[374] (2) the NYISO Membership

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366. *Southwest Power Pool, Inc.*, 126 F.E.R.C. ¶ 61,045 (2009).

367. *Id*. at P 3.

368. *Id.*

369. *Id.* at P 4.

370. *Southwest Power Pool, Inc.*, 127 F.E.R.C. ¶ 61,119 (2009).

371. *Id,* at P 3.

372. *Id.* at P 6.

373. *Id.* at P 8.

374. *Central Hudson Gas & Elec. Corp.*, 88 F.E.R.C. ¶ 61,229 at 61,758 (1999) (order accepting NYISO agreement on governance).

Agreement,[375] (3) the NYISO Market Services Tariff,[376] and (4) the NYISO's OATT[377] during the period from January 1, 2006, through October 17, 2007.[378]

The audit report found two areas of concern. "First, the report found that the NYISO's internal MMU [was] not sufficiently independent of [NYISO's] Market Structures unit, which includes a number of functions related to market design and product development."[379] The report also found that the NYISO failed to consistently notify the Commission and market participants on a timely basis when the NYISO discovers tariff-related problems.[380] The report cited a prior order of the FERC directing the

> NYISO to file a report with the Commission explaining why it did not self-report a tariff-related error to the Office of Enforcement and whether the NYISO notified its market monitor of the violation,[381] as well as earlier instances when the [FERC] told [the] NYISO to report tariff-related problems to the Commission and to notify market participants of such problems.[382]

The audit report recommended specific organizational and procedural changes within the NYISO to ensure independence of the MMU and timely identification and reporting of tariff-related violations to the FERC and the NYISO's market participants, including "conduct[ing] a formal review of processes used to identify potential tariff compliance problems, conduct[ing] internal evaluations of such problems, vet[ting] such problems with stakeholders, and seeking timely waivers or tariff revisions at the Commission as appropriate."[383]

The FERC also expressed its concerned with "the NYISO's failure to formally notify the Commission and inform market participants of its tariff-related problems in a timely manner."[384] The FERC directed the OE to report any failure of the NYISO to comply with the recommended actions in the report.[385]

3. ISO New England I

On October 26, 2009, the FERC issued an order approving staff's findings and recommendations with respect to ISO-NE' compliance with the FERC's independence requirements for an RTO pursuant to 18 C.F.R. § 35.34(j)(1) of the Commission's regulations.[386] In particular, the purpose of the audit was to evaluate whether ISO-NE was in compliance with the FERC's independence requirements, including, explicitly, testing whether ISO-NE's written procedures to comply with the FERC's requirement that ISO-NE have an independence

375. *New York Indep. Sys. Operator, Inc.*, 90 F.E.R.C. ¶ 61,015 at 61,032 (2000) (order accepting, among other things, revised NYISO Service Tariff).

376. NYISO, FERC Electric Tariff Original Volume No. 2.

377. NYISO, FERC Electric Tariff Original Volume No. 1.

378. *New York Indep. Sys. Operator, Inc.*, 127 F.E.R.C. ¶ 61,120 (2009).

379. *Id.* at P 6.

380. *Id.* at PP 5, 6, 8.

381. *Id.* at PP 8-9.

382. *Id.* at P 9.

383. *Id.* at P 12.

384. *Id.* at P 11.

385. *Id.* at P 12.

386. *ISO New England Inc.*, 129 F.E.R.C. ¶ 61,070 (2009).

audit[387] were in fact being followed.[388] The audit found that ISO-NE's decision-making process was independent of control by any market participant or class of participants, as required by 18 C.F.R. § 35.34(j)(1)(ii).[389]

The audit report also contained five recommendations for process improvements, which were that ISO-NE should:

> review and revise as necessary the language in the Code of Conduct on prohibition of accepting gifts; (2) review and revise as necessary the policy on Code of Conduct training, specifically for ISO-NE Board members; (3) review and revise as necessary the annual certification forms in order to foster full disclosure by ISO-NE employees of any and all business and financial relationships with market participants; (4) develop better controls for the ISO-NE compliance staff review of annual certifications; and (5) review NEPOOL Participant Technical Committee By-Laws to ensure that ISO-NE's By-Laws are consistent with changes in ISO-NE operations.[390]

4. ISO New England II

On August 25, 2009, the FERC issued an unpublished letter order accepting the finding and recommendation of staff with respect to an audit of ISO-NE's compliance with the FERC's accounting regulations contained in the Uniform System of Accounts under 18 C.F.R. Part 101 (2008), financial reporting requirements in FERC Form Nos. 1 and 3-Q, and related regulations during the period of January 1, 2007, through December 31, 2008.[391] The audit report identified one area of non-compliance related to ISO-NE's accounting and financial reporting processes and procedures for its pension liability, and recommended that ISO-NE strengthen its accounting and reporting to ensure proper classification of its pension liability.[392]

5. Midwest Independent Transmission System Operator

On June 9, 2009, the FERC issued an unpublished letter order accepting the report with respect to the audit of the Midwest ISO for the period January 1, 2006 through the May 27, 2008.[393] The audit report evaluated the Midwest ISO's compliance with aspects of: (1) the Open Access Transmission and Energy Market Tariff,[394] (2) the Agreement of Transmission Facilities Owners,[395] (3) the Agreement Between Midwest ISO, Midwest ISO Balancing

387. *ISO New England Inc.*, 121 F.E.R.C. ¶ 61,109 (2007) (order denying ISO-NE's motion for limited waiver of audit requirements and finding that ISO-NE must have an independence audit).

388. *See also ISO New England Inc., Deficiency Letter of the Director, Division of Tariffs & Market Development – East*, Docket No. RT04-2-017 (Jan. 5, 2009) (advising ISO-NE that its compliance filing was deficient and requiring that it be supplemented to enable the Commission to evaluate ISO-NE's independence pursuant to 18 C.F.R. § 35.34(j)(1)(iv)(A) (2006) of the Commission's regulations).

389. 129 F.E.R.C. ¶ 61,070 at P 1.

390. 129 F.E.R.C. ¶ 61,070 at P 5.

391. *ISO New England Inc., Letter Order*, Docket No. FA09-6-000 (2009).

392. *Audit of ISO New England Inc.'s Compliance with the Commission's Accounting and Financial Reporting Regulations*, Docket No. FA09-6-000, at 2, 7 (Aug. 25, 2009).

393. *Midwest Indep. Transmission Sys. Operator, Inc., Letter Order*, Docket No. PA08-28-000(2009).

394. *See, e.g.*, Midwest ISO, FERC Electric Tariff, Third Revised Volume No. 1, superseded by Midwest ISO, FERC Electric Tariff, Fourth Revised Volume No. 1. *See Midwest Indep. Transmission Sys. Operator, Inc.*, 125 F.E.R.C. ¶ 61,321 (2008) (accepting Midwest ISO's proposal for an Ancillary Services Market to take effect January 6, 2009).

395. Midwest ISO, FERC Electric Tariff, First Revised Rate Schedule No. 1 (2008).

Authorities, and the Midwest ISO Independent Market Monitor,[396] (4) the FERC's accounting and reporting requirements,[397] and (5) other obligations and responsibilities as approved by the FERC. The audit report found no areas of non-compliance, and, as such, did not issue any findings or recommendations that require the Midwest ISO to take corrective actions.

6. El Paso Electric Company

On August 12, 2009, the FERC issued an unpublished letter order accepting the findings and recommendations of an audit report evaluating El Paso Electric Company's (El Paso) compliance with the terms and conditions of its OATT for the period July 1, 2006, to May 30, 2009.[398]

The audit report identifies four areas of non-compliance under El Paso's OATT requirements: (1) refunding of transmission service deposits; (2) calculation of network customer's monthly demand charge; (3) attestation requirement for temporary termination and redesignating of network resources; and (4) expiration of network resource designation.[399] The audit report recommended, and El Paso implemented, corrective actions including: providing refunds, updating certain of its procedures under its OATT related to the provision of network service, and developing controls to remedy deficiencies with an application or a request for transmission service.[400]

7. Niagara Mohawk Power Corporation

On January 21, 2009, the FERC issued an unpublished letter order accepting the findings and recommendations of an audit report evaluating Niagara Mohawk Power Corporation d/b/a National Grid's (Niagara Mohawk) compliance with 18 C.F.R. Part 35.3, Notice Requirements, and 18 C.F.R. Part 125, Preservation of Records of Public Utilities and Licensees during the period from January 1, 2006, through December 31, 2007.[401] The audit was initiated pursuant to the FERC's "Order Accepting Interconnection Agreements Subject to Conditions, Approving Settlement, and Initiating Audit" in Docket Nos. ER07-1019, *et al*.,[402] which directs OE to conduct an audit of Niagara Mohawk.

The audit report found that Niagara Mohawk's failure to comply with the FERC's requirements was mainly the result of insufficient controls employed by the company.[403] For example, audit staff found that Niagara Mohawk: (1) had no formal procedure for reviewing the filing requirements of jurisdictional contracts; (2) did not have a consistent records preservation system, and (3) filed

396. Midwest ISO, FERC Electric Tariff, Rate Schedule No. 7 (2008).

397. 18 C.F.R. Part 101 (2009).

398. *El Paso Elec. Co., Letter Order*, Docket No. PA09-3-000 (2009).

399. *Audit of Open Access Transmission Tariff for El Paso Elec. Co.*, Docket No. PA09-3-000, at 3-4 (Aug. 12, 2009).

400. *Id.* at 10-20.

401. *Niagara Mohawk Power Corp., Letter Order*, Docket No. PA08-7-000 (2009).

402. *Niagara Mohawk Power Corp., Order Accepting Interconnection Agreements Subject to Conditions, Approving Settlement, and Initiating Audit*, 121 F.E.R.C. ¶ 61,104 (2007).

403. *Audit of Compliance with Rate Schedule and Tariff Filing Requirements and Records Preservation Requirements at Niagara Mohawk Power Corporation*, Docket No. PA08-7-000, at 4 (Jan. 21, 2009).

Electric Quarterly Reports (EQR) that were not consistent with the FERC requirements.[404]

The audit report noted that Niagara Mohawk had corrective processes and recommended that Niagara Mohawk continue to (1) evaluate existing procedures; (2) develop and implement new procedures as warranted; and (3) train its personnel on new procedures.[405] Audit staff also recommended that Niagara Mohawk develop an audit program to evaluate compliance with filing requirements, records preservation, and EQR filings.[406]

8. Order No. 890 Audits

On June 18, 2009, the FERC issued unpublished letter orders approving the findings and recommendations of three audit reports, initiated in separate dockets, regarding compliance with relevant OASIS requirements associated with the modifications from Order No. 890 during the period March 17, 2008, through April 21, 2009.[407] Audit staff's scope and methodology employed in all three audits were the same. Each audit included a review of the information posted on the company's OASIS to ensure it conformed with 18 C.F.R § 37.6 of the FERC's regulations. Audit staff's review and evaluation did not include additional obligations imposed in Order Nos. 890, 890-A, 890-B, and 890-C that are contingent on the on-going development of Business Standards by the North American Energy Standards Board.[408]

"Deseret's audit did not result in any findings or recommendations that require [the company] to take corrective actions."[409] The audit reports for Southern Company and BPA each identify areas of non-compliance and recommend corrective action. With respect to Southern Company, audit staff found two non-compliance issues: posting narrative explanations and posting load forecasts.[410] With respect to BPA, audit staff found one area of non-compliance –posting load forecasts and underlying assumptions.[411] The audit reports recommend corrective action consistent with the relevant requirements of the FERC's regulations in 18 C.F.R. § 37.6.

VII. PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978

A. JD Wind – Mandatory Purchase Obligation

In *JD Wind*,[412] the FERC declined to initiate an enforcement action pursuant to section 210(h) of the Public Utility Regulatory Policies Act of 1978,

404. *Id.*

405. *Id.* at 4-5.

406. *Id.* at 9-18.

407. *Southern Co.*, Docket No. PA09-13-000 (2009); *Bonneville Power Admin.*, Docket No. PA09-11-000 (2009); *Deseret Generation & Transmission Cooperative, Inc.*, Docket No. PA09-8-000 (2009).

408. *Id.*

409. *Deseret Generation & Transmission Cooperative, Inc*., Docket No. PA09-8-000, at 3 (2009).

410. *Audit of Open Access Same-time Information System Requirements at Southern Co*., Docket No. PA09-13-000, at 2 (Jun. 18, 2009).

411. *Audit of Open Access Same-time Information System Requirements at Bonneville Power Administration*, Docket No. PA09-11-000, at 6 (Jun. 18, 2009).

412. *JD Wind 1, L.L.C.*, 129 F.E.R.C. ¶ 61,148 (2009), *reh'g pending*.

as amended (PURPA)[413] in connection with a wind qualifying facility (QF) developer's attempt to enter into long-term contracts with an electric utility. However, the FERC held that a May 1, 2009 decision of the Public Utility Commission of Texas (Texas PUC) concerning such contracts was inconsistent with the requirements of PURPA and the FERC's regulations implementing PURPA.

The case arose when the wind QF developer sought to require the utility with which its QF facilities are interconnected to enter into long-term contracts with prices set at the utility's avoided cost rates determined at the time the contracts were negotiated. The Texas PUC determined that the developer had not offered "firm power" and therefore the developer could not create a "legally enforceable obligation" requiring the utility to enter into the contracts under PURPA.[414] The developer therefore requested that the FERC enforce PURPA and declare that the Texas PUC decision conflicted with PURPA and the FERC's implementing regulations.[415]

After reviewing the PURPA enforcement provisions, the FERC declined to exercise its discretionary authority and initiate an enforcement action against the Texas PUC.[416] The FERC nonetheless held that the Texas PUC's decision denying the wind QF developer a legally enforceable obligation and the requirement in Texas law that legally enforceable obligations are available only to sellers of "firm power" are inconsistent with PURPA and the FERC's implementing regulations.[417] The FERC reviewed the purpose of PURPA's mandatory-purchase obligation and its implementing regulations,[418] held that its regulations do not distinguish between "firm" and "non-firm" power,[419] and concluded that a QF "may choose either: (1) to sell as-available energy whenever it determines such energy is available; or (2) sell capacity or energy for a fixed term, pursuant to a mutually agreed-to contract, or pursuant to a contract or other legally enforceable obligation imposed on the utility by the state regulatory authority."[420] If the QF chooses the latter option, it then has the option to choose a rate based on avoided costs calculated at the time of delivery or calculated at the time the obligation is incurred.[421] The FERC noted that the "firmness" of the QF's power may affect the avoided cost rate.[422] The matter remained on rehearing at year end.

B. Termination of Purchase Obligation

Several utilities sought and received, under PURPA section 210(m),[423] FERC authorization of the termination on a service territory-wide basis of the

413. 16 U.S.C. § 824a-3(h) (2006).
414. 129 F.E.R.C. ¶ 61,148 at PP 2-3.
415. *Id.* at PP 4, 19.
416. *Id.* at PP 20-22.
417. *Id.* at P 23 (citing 18 C.F.R. § 292.304(d) (2009)).
418. *Id.* at PP 24-25.
419. *Id.* at P 27.
420. *Id.* at P 27.
421. *Id.* at PP 25, 27.
422. *Id.* at P 28.
423. 16 U.S.C. § 824a-3(m) (2006).

obligation to enter into new power purchase obligations or contracts to purchase electric energy and capacity from QFs with net capacity in excess of 20 MW. These utilities included Montana-Dakota Utilities Co.,[424] MidAmerican Energy Co.,[425] and PPL Electric Utilities Corp.[426] In each case, the FERC found that the applicant utility was located in a market for which the FERC had established a rebuttable presumption that large QFs (over 20 MW net capacity) interconnected with member electric utilities in the market had nondiscriminatory access to independently administered, auction-based day-ahead and real-time wholesale markets for the sale of electric energy, and wholesale markets for long-term sales of capacity and electric energy. The FERC also found that no QFs had challenged the requested termination. Accordingly, the FERC terminated the utility's obligation to enter into new purchase obligations or contracts.

C. Sun Edison – Jurisdictional Sales

In a declaratory order,[427] the FERC confirmed that certain sales by QFs to end-use customers do not constitute FERC-jurisdictional wholesale sales or transmission of electric energy in interstate commerce and do not involve FERC-jurisdictional rates for purposes of the Public Utility Holding Company Act of 2005 (PUHCA 2005). In particular, the petitioner sought the rulings with respect to its retail sales of electric energy generated by its solar-powered QFs located on property controlled by the end-use customer, which purchased the electricity for use on-site. The petitioner stated that, at times, the electrical output of the QFs could exceed the retail customer's load. In those circumstances, under the applicable state-authorized "net metering" programs, the excess energy would flow back through the interconnection to the grid, with the deliveries netted against the customer's electric purchases from the local utility. The petitioner sought confirmation that neither such deliveries nor its sales to the end-use customers constituted FERC-jurisdictional wholesale sales or transmission.[428]

The FERC granted the requested confirmation. The FERC explained that, in a typical net metering program, a FERC-jurisdictional sale occurs only if the end-use customer generating power on-site produces more energy than it needs over the applicable billing period.[429] The FERC held that, consistent with applicable net metering precedent,

> where the net metering participant (i.e., the end-use customer that is the purchaser of the solar-generated electric energy from [the petitioner]) does not, in turn, make a net sale to a utility, the sale of electric energy by [the petitioner] to the end-use customer is not a sale for resale.[430]

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424. *Montana-Dakota Utils. Co.*, 126 F.E.R.C. ¶ 61,121 (2009).
425. *MidAmerican Energy Co.*, *Letter Order*, Docket No. QM09-5-000 (2009).
426. *PPL Elec. Utils. Corp.*, *Letter Order*, Docket No. QM09-6-000 (2009).
427. *Sun Edison, L.L.C.*, 129 F.E.R.C. ¶ 61,146 (2009).
428. *Id.* at PP 3-11.
429. *Id.* at P 18.
430. *Id.* at P 19.

Similarly, sales by the petitioner of energy from its solar QF facilities do not constitute FERC-jurisdictional rates under PUHCA 2005 because they are not FERC-jurisdictional sales or transmission.[431]

The FERC declined, however, to grant waivers requested by the petitioner. The FERC held that the petitioner was required to obtain QF certification for each of its solar generating facilities (through either a notice of self-certification or an application for FERC certification), and such certification exempted the petitioner from the regulations of which it requested waiver.[432] The FERC explained that the QF self-certification process was "designed to be relatively quick and easy,"[433] and therefore the petitioner's claim of burden was "misplaced."[434] The FERC also noted that the petitioner could contact FERC staff to "discuss methods of self-certification that may not require a separate filing for each rooftop solar facility."[435]

IX. GENERATOR INTERCONNECTIONS

A. Midwest Independent Transmission System Operator

On June 26, 2008, the Midwest ISO proposed revisions in the first phase of its interconnection queue reform to streamline the processing of interconnection requests, limit delay caused by inactive projects in the queue, and move from a "first come, first served" approach to a "first ready, first served" process.[436] The Commission accepted the majority of the Midwest ISO's proposed revisions in subsequent orders in Docket No. ER08-1169.[437] These revisions included: (1) permitting projects that are prepared to proceed faster to move into a new Definitive Planning Phase without being delayed; (2) instituting Group Study as the primary study method to speed the processing of requests and permitting withdrawn projects to be replaced by the next similarly situated project to reduce the need for restudies; (3) limiting suspension of a project to circumstances of unforeseeable "Force Majeure" events and requiring projects that suspend to post security to pay for restudies caused by the suspension to eliminate commercial uncertainty and reduce the use of suspension as a business decision; (4) increasing milestone deposits required from projects to remain in the queue to reduce the number of speculative projects in the queue; and (5) modifying

431. *Id.* at P 20.

432. *Id.* at P 21.

433. *Id.* at P 22.

434. *Id.* at P 23.

435. *Id.* at P 22.

436. *See Interconnection Queuing Practices, Order on Technical Conference*, 122 F.E.R.C. ¶ 61,252 at P 18 (2008) ("March 20 Order") (noting that a "first ready, first served" process is one of the variations that could accelerate queue processing). *See Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, FERC STATS. & REGS. ¶ 31,146 (2003) ("Order No. 2003"), *order on reh'g*, Order No. 2003-A, FERC STATS. & REGS. ¶ 31,160 ("Order No. 2003-A), o*rder on reh'g*, Order No. 2003-B, FERC STATS. & REGS. ¶ 31,171 (2004) ("Order No. 2003-B"), o*rder on reh'g*, Order No. 2003-C, FERC STATS. & REGS. ¶ 31,190 (2005) ("Order No. 2003-C"), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007).

437. *Midwest Indep. Transmission Sys. Operator, Inc.*, 124 F.E.R.C. ¶ 61,183 (2008). On June 25, 2009, the Commission issued two orders: (1) *order on reh'g*, 127 F.E.R.C. ¶ 61,294 (2009); (2) *order on compliance*, 127 F.E.R.C. ¶ 61,295 (2009).

milestones to increase the requirement for technical information and financial and non-financial milestones as indicators of readiness.[438]

The second phase of the Midwest ISO's revisions to its Generator Interconnection Procedures (GIP) focused on expediting the construction of network upgrades to the transmission system to accommodate the high volume of interconnection requests in wind-rich regions driven by Renewable Portfolio Standards (RPS) in seven states (Illinois, Iowa, Michigan, Minnesota, Missouri, Ohio, and Wisconsin).[439] The clustering of interconnection requests in certain wind-rich regions resulted in multiple interconnection customers jointly causing the need for upgrades and requiring separate agreements with affected systems and with multiple interconnection customers to construct and finance the facilities necessary to support the interconnection of new generation.[440]

To address these concerns, the Midwest ISO worked with stakeholders through its Interconnection Process Task Force (IPTF) and proposed revisions to revise its GIP to include two new *pro forma* agreements: a facilities construction agreement (FCA) for a single Interconnection Customer and a multi-party facilities construction agreement (MPFCA) to address the situation where multiple Interconnection Customers cause the need and share the cost responsibility for common use upgrade (CUU) to accommodate their generator interconnection requests.[441] The certainty of a standard *pro forma* agreement template for the FCA and MPFCA and the designation of certain upgrades as CUU to be jointly funded upfront by multiple interconnection customers were intended to expedite the construction of needed facilities on affected systems by reducing the time and expense incurred in negotiating and filing FCAs and MPFCAs with the Commission.[442] The Commission conditionally accepted these revisions, subject to a compliance filing due on Feb. 1, 2010.[443]

B. PJM Interconnection

In accordance with the Commission's Order Approving Contested Settlement issued April 10, 2008, in Docket No. EL08-36, PJM filed proposed revisions to its OATT in 2008 and 2009.[444] Pursuant to the terms of the

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438. *Transmittal Letter*, Docket No. ER08-1169-000 (June 26, 2008).

439. *Midwest Indep. Trans. Sys. Operator, Inc.*, 124 F.E.R.C. ¶ 61,183 at P 11 note 8 (explaining that the RPS "are state policies that require electricity providers to obtain a minimum percentage of their power from renewable energy resources by a certain date"). In addition, North Dakota and South Dakota have state renewable portfolio goals.

440. *Midwest Indep. Trans. Sys. Operator, Inc.*, 124 F.E.R.C. ¶ 61,183 at PP 9-16 (discussing the effect of the RPS in the Midwest ISO's interconnection queue). As an example, the Commission noted that in the Buffalo Ridge area in Minnesota, "[t]here are approximately 23 GW of wind generation requests for interconnection by 2014, while only approximately 1.9 GW of additional transmission capacity is planned for the region by that date." *Id.* at P 12.

441. *See generally* Order No. 2003, *Standardization of Generator Interconnection Agreements and Procedures*, 104 F.E.R.C. ¶ 61,103 at P 12 (2003)(noting that the use of standard procedures and a standard agreement serve several important functions including reducing interconnection costs and time and encouraging investment in generator and transmission infrastructure).

442. *See generally id*. at PP 12, 913; (noting that conforming service agreements need not be filed with the Commission).

443. *Midwest Indep. Transmission Sys. Operator, Inc.*, 129 F.E.R.C. ¶ 61,301 (2009).

444. *See generally Dominion Res. Servs., Inc. v. PJM Interconnection, L.L.C.*, 123 F.E.R.C. ¶ 61,025 (2008).

settlement, the order approving the settlement directed PJM to re-charter the Regional Planning Process Working Group (RPPWG) to "evaluate queuing issues" and to undertake a meaningful stakeholder process to obtain the endorsement of the PJM stakeholder committees of changes to the PJM Tariff to reform the present interconnection queue and study process.[445] In accordance with the settlement, on May 30, 2008, PJM filed tariff revisions to the PJM Tariff with respect the following: (1) cluster studying of queued projects; (2) feasibility study deposits; (3) studies of the primary and secondary Points of Interconnection during the feasibility study; (4) cost allocation betweens queues; and (5) scheduling of the scoping meeting.[446] The Commission accepted these tariff revisions by Letter Order dated August 19, 2008.[447]

On October 2, 2008, PJM filed tariff revisions to clarify procedures regarding Capacity Interconnection Rights.[448] The FERC accepted this filing by Letter Order dated November 6, 2008.[449]

In 2009, PJM made additional filings in the dockets below:

- Docket No. ER09-755: On February 25, 2009, PJM filed tariff revisions to (1) revise the deposit fees related to System Impact Studies; (2) require that a Transmission Interconnection Customer show, within 30 days of submitting an Interconnection Request with PJM, that it has a valid interconnection request with adjacent Control Areas, if necessary; and (3) clarify language concerning Capacity Interconnection Rights with respect to generation Deactivation.[450] The FERC accepted this filing by Letter Order dated March 25, 2009.[451]
- Docket No. ER09-978: On April 9, 2009, PJM filed proposed revisions to its OATT to: (1) revise the deposit fees related to Facilities Studies for projects that are equal to or less than 20 megawatts (MW) in size and revise Facilities Study procedures; (2) ensure collection of past due invoices before an Interconnection Customer can proceed through the interconnection process; and (3) include an optional milestone in the Facilities Study Agreement to show site control for certain Attachment Facilities. The FERC accepted this filing by Letter Order dated June 8, 2009, subject to further compliance.[452] PJM made a compliance filing on July 8, 2009, which was subsequently accepted by letter order.[453]

445. *Id*.
446. *Transmittal Letter*, Docket No. EL08-36-001 (May 30, 2008).
447. *PJM Interconnection, L.L.C., Letter Order*, Docket No. EL08-36-001 (Aug. 19, 2008).
448. *Transmittal Letter*, Docket No. ER09-26-000 (Oct. 2, 2008).
449. *PJM Interconnection, L.L.C., Letter Order*, Docket No. ER09-26-000 (Nov. 6, 2008).
450. *Transmittal Letter*, Docket No. ER09-755-000 (Feb. 25, 2009).
451. *PJM Interconnection, L.L.C., Letter Order*, Docket No. ER09-755-000 (2009).
452. *PJM Interconnection, L.L.C., Letter Order*, 127 F.E.R.C. ¶ 61,228 (2009).
453. *PJM Interconnection, L.L.C., Letter Order*, Docket No. ER09-978-000 (2009).

C. ISO New England

Following the Commission's order on interconnection queuing practices[454] and experiencing a queue backlog of its own,[455] ISO-NE filed an interconnection reform proposal with the Commission on October 31, 2008.[456] The FCM/Queue Amendments proposed revisions to the ISO-NE Transmission, Markets and Services Tariff (ISO-NE OATT) to resolve issues related to the relationship between the FCM rules and the generator interconnection procedures set forth in Schedules 22 and 23 of the ISO-NE OATT.

Specifically, the FCM/Queue Amendments incorporated the FCM deliverability standard, known as the overlapping interconnection impacts test, as the intra-zonal deliverability standard in the interconnection procedures.[457] In doing so, the FCM/Queue Amendments created two different levels of interconnection service: (1) Capacity Network Resource Interconnection Service and (2) Network Resource Interconnection Service.[458]

The FCM/Queue Amendments also proposed a number of additional requirements and milestones with respect to processing interconnection service requests so as to improve management over large generating facility interconnection requests, and to coordinate with the FCM qualification requirements under the FCM rules.[459]

With respect to the interconnection queuing process, the FCM/Queue Amendments incorporated a "first-cleared-first-served" construct to allocate interconnection capacity rights to generating resources that demonstrate their ability and commitment to provide capacity to meet New England Installed Capacity Requirements.[460] The FCM/Queue Amendments further provided for a Conditional Qualified New Generating Capacity Resource option, which allows a resource with a lower queue position with the same overlapping interconnection impact as a resource with a higher position to conditionally qualify for the Forward Capacity Auction.[461] The FCM/Queue Amendments also incorporated a Long Lead Time Generating Facility option for facilities that would not be able to qualify for participation in an earlier Forward Capacity Auction due to the facilities development cycle or the long development period of the transmission upgrades associated with the facility.[462]

On January 30, 2009, the Commission accepted the proposed revisions to the ISO-NE OATT, without modification, effective February 1, 2009.[463]

454. *Interconnection Queuing Practices*, 122 F.E.R.C. ¶ 61,252 at P 15 (2008).

455. *See generally ISO New England Inc.'s Interconnection Queuing Practices Status Report*, Docket No. AD08-2-000 (Apr. 21, 2008).

456. *Joint Filing of Proposed Revisions to the Generator Interconnection Process and Forward Capacity Market Participation Provisions Set Forth in the ISO New England Inc. Transmission, Markets and Services Tariff*, Docket Nos. ER09-237-000, *et al.* (Oct. 31, 2008) [hereinafter *October 31*].

457. *Id*. 26.

458. *Id.* at 26-29.

459. *Id.* at 29-32, 40-43.

460. *Id.* at 31-32.

461. *Id.* at 32-35.

462. *Id.* at 35-39.

463. *ISO New England Inc.*, 126 F.E.R.C. ¶ 61,080 (2009).

On July 14, 2009, however, the Commission accepted additional clarifications made to the FCM rules, effective July 15, 2009.[464] The ISO-NE proposed a Capacity Network Resource Capability Cap, where a resource's available hourly MWs may not exceed that resource's Capacity Network Resource Capability.[465] The Commission approved the amendment as necessary to prevent MWs that have not achieved Capacity Network Resource Interconnection Service from circumventing deliverability requirements and being counted as capacity.[466]

D. California Independent System Operator Corporation

On May 15, 2008, the CAISO filed a petition for waiver of certain provisions of its Large Generator Interconnection Procedures (LGIP), which constituted the first step in the CAISO's large generator interconnection reform process. CAISO's waiver petition was approved on July 14, 2008.[467] On July 28, 2008, CAISO filed the second step in its GIPR tariff revisions, proposing amendments to its tariff. CAISO asserted that the object of its GIPR tariff amendment was, among other things: (1) to clear the existing backlog of generator interconnection requests; (2) to balance generation developer flexibility with increased generation developer commitments; and (3) to provide interconnection customers with significant certainty regarding network upgrade costs. In a September 26, 2008 order, the Commission conditionally accepted CAISO's proposed GIPR tariff revisions.[468]

In November 2008, CAISO had submitted additional tariff revisions to comply with the Commission's September 26, 2008 order – these reformed interconnection provisions included revisions to the LGIP as well as revisions to certain LGIP appendices such as the large generator interconnection study process agreement, to accommodate CAISO's three stages of interconnection queue management reform: the serial study group, the transition cluster study group and the queue cluster study group. These revisions were accepted by the Commission in a September 17, 2009 order.[469] Meanwhile, on September 18, 2009, in Docket No. ER09-1722, CAISO filed to revise provisions of its LGIP for interconnection requests in a queue cluster window, as part of its GIPR. In the same filing, under Docket No. ER08-1317, CAISO also submitted a revision directed by the Commission the prior day, in its September 17, 2009 order.[470]

On November 17, 2009, the Commission accepted CAISO's September 2009 filings revising its LGIP for interconnection requests in a queue cluster window.[471] In the same order, the Commission also established paper hearing

464. *ISO New England Inc.*, 128 F.E.R.C. ¶ 61,023 (2009).

465. *ISO New England Inc. and New England Power Pool, Various Revisions to FCM Rules, Related to Rights and Obligations, Payments and Charges, and Performance*, Docket No. ER09-1144-000 (May 15, 2009).

466. *Id.* at P 57.

467. *Cal. Indep. Sys. Operator Corp*., 124 F.E.R.C. ¶ 61,031 (2008), *reh'g denied*, 124 F.E.R.C. ¶ 61,293 (2008).

468. *Cal. Indep. Sys. Operator Corp*., 124 F.E.R.C. ¶ 61,292 (2008), *reh'g denied*, 127 F.E.R.C. ¶ 61,177 (2008).

469. *Cal. Indep. Sys. Operator Corp*., 128 F.E.R.C. ¶ 61,247 (2009).

470. *Id.* at P 28.

471. *Cal. Indep. Sys. Operator Corp.*, 129 F.E.R.C. ¶ 61,124 (2009).

procedures pursuant to section 206 of the FPA, in Docket No. EL10-15, to determine the justness and reasonableness of existing CAISO tariff provisions relating to an interconnection customer's financial security obligation following the customer's election to switch from full capacity deliverability service to energy-only deliverability service pursuant to the GIPR. The section 206 proceeding was ongoing at year end.

E. Southwest Power Pool

Following the Commission's technical conference on queue reform, and finding its current interconnection processing to be inefficient, SPP began to develop tariff revisions to its interconnection procedures through its stakeholder process. To address its queue backlog as soon as possible, SPP submitted in Docket No. ER09-262 a request for a limited, one-time waiver of various provisions in its interconnection procedures to allow for the formation of two transitional clusters of approximately 15,000 MW each.[472] The Commission conditionally granted the waiver request, ordering SPP to submit a timeline for the completion of the transitional cluster study process.[473] The Commission accepted SPP's proposed timeline in Docket No. ER09-262 on May 18, 2009.[474]

On June 1, 2009, SPP submitted a filing in Docket No. ER09-1254 to reform its interconnection procedures. Among other things, SPP proposed to create the following three interconnection study queues with different deposit and milestone requirements: (1) the feasibility study queue (feasibility queue), which would result in a feasibility study completed within ninety days of the close of a cluster window; (2) the preliminary interconnection system impact study queue (preliminary queue), which would result in a system impact study completed within 180 days of the close of a cluster window; and (3) the definitive interconnection system impact study queue (definitive queue), which would be the first required stage within the interconnection process and would result in a system impact study completed within 120 days and a facilities study completed within ninety days. SPP also proposed more stringent suspension requirements and a transition process to the new interconnection procedures.

On July 31, 2009, the Commission conditionally accepted SPP's filing, subject to a further compliance filing, and the submission of annual reports so that the Commission and interested stakeholders could monitor SPP's progress in processing its queue backlog and assess the effectiveness of its new interconnection procedures.[475] On August 31, 2009, SPP submitted a filing to comply with the Commission's July 31, 2009 queue reform order, and on December 17, 2009, the Commission conditionally accepted SPP's compliance filing, subject to the submission of another compliance filing.[476]

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472. *See generally Southwest Power Pool, Inc.*, 126 F.E.R.C. ¶ 61,012 (2009), *order on reh'g*, 126 F.E.R.C. ¶ 61,215 (2009).

473. *Id.* at P 37.

474. *Southwest Power Pool, Inc.*, 127 F.E.R.C. ¶ 61,138 (2009), *order on reh'g*, 129 F.E.R.C. ¶ 61,145 (2009). According to the proposed timelines, SPP would issue the final facilities study report for the first transitional cluster by March 24, 2010 and issue the final facilities study report for the second transitional cluster by September 16, 2010.

475. *Southwest Power Pool, Inc.*, 128 F.E.R.C. ¶ 61,114 (2009).

476. *Southwest Power Pool, Inc*., 129 F.E.R.C. ¶ 61,226.

F. New York Independent System Operator

Unlike other ISOs/RTOs that focused on interconnection queue reform over this past year, the NYISO's significant development involved the implementation of a deliverability standard in its facility interconnection procedures.

On October 5, 2007, the NYISO and the NYTOs (collectively, Joint Parties), in compliance with the Commission's August 6, 2004 and June 2, 2005 orders,[477] submitted a proposed Consensus Deliverability Plan related to the implementation of a second level of interconnection service with a deliverability component in the New York Control Area. The conceptual proposal for adding to the NYISO's OATT a second level of interconnection service with a deliverability component was developed with NYISO stakeholders through the Interconnection Issues Task Force. On March 21, 2008, the Commission issued a guidance order which approved the conceptual framework reflected in the Consensus Deliverability Plan.[478]

On August 5, 2008, the Joint Parties submitted their joint compliance filing containing amendments to the NYISO's OATT and Services Tariff necessary to implement the directives of the March 21, 2008 order. These amendments were known as the NYISO Deliverability Plan. Under the revised NYISO Tariff, generators could choose a basic interconnection service, Energy Resource Interconnection Service, that would allow them to participate only in the NYISO's energy and ancillary services market. Generators could also choose the new Capacity Resource Interconnection Service, which would provide basic interconnection service and allow a generator to participate in the NYISO's installed capacity market "to the extent the generator's capacity is deliverable."[479]

As proposed, the new capacity interconnection service will require deliverability only within a previously designated capacity region of the NYISO, not the entire NYISO. These capacity regions are established separately for purposes of administering the NYISO installed capacity market.

On January 15, 2009, the Commission issued an order conditionally accepting the August 5 filing subject to further clarifications and modifications.[480] The Commission found that the NYISO's filing lacked sufficient detail regarding the issue of the proposed treatment of External Resources, but did not rule on the merits of the proposal regarding the treatment of External Resources. Instead, the Commission directed the NYISO to submit a compliance filing within thirty days "clarify[ing] how the revised tariff sheets addressing deliverability tests for internal and external resources meet the 'independent entity variation standard' for revising the terms of the *pro forma* Large Generator Interconnection Agreement and *pro forma* Large Generator Interconnection Procedures to accommodate regional needs."[481] The Commission also directed tariff sheet modifications within thirty days to: (1)

477. *N.Y. Indep. Sys. Operator, Inc*., 108 F.E.R.C. ¶ 61,159 at P 28 (2004); *N.Y. Indep. Sys. Operator, Inc*., 111 F.E.R.C. ¶ 61,347 at P 14 (2005).

478. *N.Y. Indep. Sys. Operator, Inc.,* 122 F.E.R.C. ¶ 61,267 (2008).

479. 126 F.E.R.C. ¶ 61,046 at P 7 (2009).

480. *Id*.

481. *Id*. at P 20.

clarify the definition of Energy Resource Interconnection Service (ERIS); (2) differentiate the requirements for customers seeking Capacity Resource Interconnection Service (CRIS) from the requirements for customers taking ERIS; (3) clarify that the annual application of deliverability to External Resources does not impact established Unforced Deliverability Rights; and (4) clarify that a Developer may seek CRIS at any time pre- or post-construction or operations. The Commission also directed the Joint Parties to develop and file revised tariff sheets resolving the Load Serving Entity funding mechanism within six months. Several parties made filings requesting for rehearing of the January 15 order.

On May 4, 2009, NYISO and the NYTOs filed amendments to NYISO's OATT and Services Tariff. Among the revisions to the Tariff, NYISO: (1) clarified the definition of ERIS to include ancillary services; (2) differentiated the requirements for customers seeking CRIS from the requirements for customers taking ERIS; (3) clarified that a Generator taking ERIS may seek CRIS at any later date; and (4) clarified that the annual application of the deliverability test is not applicable to External Resources associated with Unforced Deliverability Rights. Under NYISO's External Resources proposal, external Installed Capacity suppliers may request external CRIS rights if that supplier makes a long-term commitment of five years or more to supply installed capacity to New York. This commitment would allow the supplier to avoid the annual re-evaluation of deliverability and would not have to be re-evaluated until the external CRIS rights expire.

On June 30, 2009, the Commission issued an order accepting the revisions and clarifications proposed in the NYISO's May 4 compliance filing as consistent with the Commission's January 15, 2009 order.[482] With regard to the External Capacity Resource Interconnection Service Rights Proposal, the Commission accepted the proposal in principle and directed the NYISO to file Tariff revisions within 120-days. The Commission also directed the NYISO to submit criteria for the development of additional capacity zones in the NYISO market by October 5, 2010.

On October 28, 2009, the NYISO made its 120-day compliance filing, setting forth amendments to the NYISO Tariff to implement the External Capacity Resource Interconnection Service Rights Proposal.[483] The revisions provide capacity resources external to the NYISO control area with the opportunity to obtain a long-term determination of deliverability. The Commission issued a letter order on December 28, 2009 accepting the NYISO's October 28 compliance filing.

With regard to the six-month compliance directive set forth in the Commission's January 15, 2009 order, the compliance filing time period was ultimately moved to November 15, 2009. On November 13, 2009, the NYISO made its six-month compliance filing, proposing a Highway Facilities Charge (HFC) under a new Rate Schedule 12 to the NYISO OATT.[484] According to the

482. *New York Indep. Sys. Operator, Inc.*, 127 F.E.R.C. ¶ 61,318 (2009).

483. *Joint Compliance Filing of the New York Independent System Operator, Inc. and the New York Transmission Owners*, Docket No. ER04-449-020 (Oct. 28, 2009).

484. *Joint Compliance Filing of the New York Independent System Operator, Inc. and the New York Transmission Owners*, Docket No. ER04-449-021 (Nov. 13, 2009).

NYISO, the HFC will allow it to recover the LSE portion of the costs for Highway SDUs from LSEs, credit those payments to the relevant Transmission Owners, and adjust the costs charged to LSEs as appropriate to reflect new projects' use of LSE-created headroom. Commission action on this compliance filing is still pending.

On August 27, 2009, the NRG companies filed a petition for review of the Commission's January 15, 2009 order and the June 30, 2009 order on rehearing with the D.C. Circuit.

X. ORDERS REQUIRING TRANSMISSION SERVICE

While the FERC was active in a variety of areas throughout 2009, it addressed FPA section 211 on only one occasion. In *Powerex Corp.*, the FERC directed Nevada Power Company to provide transmission service to Powerex Corp. pursuant to FPA section 211.[485] As set forth in the order, service was to commence on April 1, 2009.[486]

By way of background, FPA section 211 was enacted in 1978 as one component of PURPA.[487] Under FPA section 211, any electric utility, federal power marketing agency, or any other person generating electric energy for sale for resale may apply to the FERC for an order requiring a transmitting utility to provide transmission services to the applicant. Prior to issuing such an order, the FERC must determine that the public interest warrants such an order and that issuance of an order will not pose a risk to the reliability of the Bulk-Power System. Further, unless the transmitting utility waives the requirement, the utility seeking an order from the FERC must first request transmission service from the transmitting utility at least sixty days before seeking an order from the FERC.[488]

In *Powerex Corp.*, the FERC issued an order pursuant to FPA section 211, in response to a request by Powerex, which directed Nevada Power Company to provide transmission service to Powerex Corp. The FERC determined that issuance of such an order would not impair the reliability of the Bulk-Power System, and that such an order was required by the public interest.[489] In determining that granting Powerex's request was required by the public interest, the FERC relied on prior precedent that "the availability of transmission service enhances competition in power markets by increasing power supply options of buyers and sales options of sellers, and that this should result in lower costs to consumers."[490] As such, the FERC found that directing Nevada Power Company to provide transmission service would result in lower costs to consumers, and therefore was required by the public interest.[491]

485. *Powerex Corp.*, 126 F.E.R.C. ¶ 61,077 (2009).

486. 126 F.E.R.C. ¶ 61,077 at P 1.

487. 16 U.S.C. § 824j (2006).

488. 16 U.S.C. § 824j(a) (2006).

489. 126 F.E.R.C. ¶ 61,077 at P 8.

490. *Id.* (*citing Florida Municipal Power Agency v. Florida Power & Light Co.*, 65 F.E.R.C. ¶ 61,125 (1993), *reh'g dismissed*, 65 F.E.R.C. ¶ 61,372 (1993), *final order*, 67 F.E.R.C. ¶ 61,167 (1994), *order on reh'g*, 74 F.E.R.C. ¶ 61,006 (1996), *order on reh'g*, 96 F.E.R.C. ¶ 61,130 (2001)).

491. 126 F.E.R.C. ¶ 61,077 at P 8.

Notably, Nevada Power Company did not oppose providing transmission service to Powerex. However, Nevada Power Company explained that it could not maintain tax-exempt status on local furnishing bonds by providing transmission service to Powerex unless the FERC issued an order under section 211 of the FPA directing Nevada Power Company to provide service. For this reason, Nevada Power Company waived the requirement that Powerex first request service and then wait sixty days until filing an application for an order with the FERC.[492]

The FERC's order in *Powerex Corp.* is similar to a 2005 decision involving a request by PacifiCorp that the FERC direct Nevada Power Company to provide transmission service.[493] In that case, Nevada Power Company argued that it would lose its tax-exempt status on local furnishing bonds unless directed to provide service by the FERC. The FERC directed Nevada Power Company to provide the service requested in that case as well.[494]

XI. ORDERS RULING ON COMPLAINTS (EXCLUDING RTO MATTERS)

On January 16, 2009, the FERC denied a complaint under FPA section 206 filed by Arkansas Electric Energy Consumers, Inc. (Arkansas Consumers) against Entergy Corporation and its subsidiaries (collectively, Entergy) relating to the acquisition of the 789 MW Ouachita Generation Facility (the Ouachita Plant) by one of the operating utility subsidiaries – Entergy Arkansas, Inc. (Entergy Arkansas) – and the sale of a portion of the Ouachita Plant's output to another of the operating utility subsidiaries – Entergy Gulf States, Inc. (Entergy Gulf States).[495] The complaint alleged that: (1) allocation of one-third of the output of the Ouachita Plant to Entergy Gulf States violates a system agreement that provides the contractual basis for the operating utility subsidiaries to operate as a single integrated electric system; (2) the retail customers of Entergy Arkansas will be compelled to subsidize the other operating utility subsidiaries and their customers, in violation of FPA section 206; (3) in light of the expected 2013 withdrawal of Entergy Arkansas from the system agreement, the FERC should determine that Entergy can no longer plan generation acquisitions on the basis of a single integrated system basis; and (4) the two-thirds of the output of the Ouachita Plant dedicated to retail service should be determined to be solely an Entergy Arkansas resource.[496]

With respect to the first allegation, the FERC found that the allocation of the Ouachita Plant capacity does not violate any of the terms or conditions of the system agreement.[497] The FERC rejected the subsidization allegation based on a finding that the assignment of costs to the operating utility subsidiaries by the system agreement "properly compensate[s] Entergy Arkansas and its [customers] for any of the Ouachita Plant's capacity and energy that is purchased for use by the other [operating utility subsidiaries]."[498] The third allegation was rejected by

492. *Id.* at P 7.

493. *PacifiCorp*, 111 F.E.R.C. ¶ 61,070 (2005).

494. *Id.*

495. *Ark. Elec. Energy Consumers, Inc. v. Entergy Corp.*, 126 F.E.R.C. ¶ 61,051 (2009).

496. *Id.* at P 8.

497. *Id.* at P 19.

498. *Id.* at P 33.

the FERC as premature because the existing system agreement remains in effect.[499] The FERC refused to declare the Ouachita Plant to be a resource solely for Entergy Arkansas because the Ouachita Plant "was acquired as part of Entergy's overall system planning with the intent that [the plant's energy be a system] resource."[500]

On January 16, 2009, the FERC denied without prejudice a complaint under FPA section 206 filed by NRG Energy, Inc. and its affiliated companies (collectively, NRG) against Entergy relating to Entergy's transmission rate formula for transmission service under its OATT.[501] The complaint alleged that Entergy's transmission rate formula is unjust and unreasonable because it allows Entergy to pass through to its transmission service customers the bonus compensation paid to Entergy's employees without any evidence that the bonus payments are related to the provision of transmission service. The FERC found that NRG failed to provide factual support for its allegations.[502] Based on this failure of proof and on "Entergy's explanation of its employee compensation, allocation and accounting practices with respect to transmission-related expenses" the FERC concluded that NRG had not met its burden under FPA section 206 to demonstrate that Entergy's existing rate formula is unjust and unreasonable.[503] The complaint was dismissed without prejudice to NRG's filing a new complaint with adequate evidence.

On April 16, 2009, the FERC denied a complaint under FPA section 206 submitted by Interstate Power and Light Company (Interstate) against ITC Midwest, L.L.C. (ITC Midwest) seeking relief from ITC Midwest's allegedly improper implementation of its formula rate for FERC-jurisdictional transmission service for 2009 and subsequent years.[504] Interstate alleged that: (1) ITC Midwest's formula rate implementation was improper because ITC Midwest included in its transmission charges excessive and extraordinary projected operations and maintenance (O&M) expenses and administrative and general (A&G) expenses, resulting in unjust and unreasonable transmission service charges in 2009 and later years; (2) ITC Midwest failed to satisfy its obligation under its annual rate calculation and true-up procedures to provide to Interstate adequate information about ITC Midwest's expenditures and rate calculations; and (3) ITC Midwest's parent, ITC Holdings Corporation (ITC Holdings), inappropriately used the Massachusetts Formula to allocate non-directly assigned A&G costs to ITC Midwest.

The FERC generally found that Interstate's complaint consisted largely of unsubstantiated allegations insufficient to warrant a hearing. The FERC specifically determined that Interstate failed to meet its burden under FPA section 206 "to demonstrate that the O&M and A&G expenses may be excessive or that the projected and true-up transmission rates may be unjust and unreasonable;" that Interstate failed to specify the ITC Midwest information it allegedly needs and to which it has allegedly been denied access; and that

499. *Id.* at P 38.

500. *Id.* at P 46.

501. *NRG Energy, Inc. v. Entergy Servs., Inc.*, 126 F.E.R.C. ¶ 61,053 (2009).

502. *Id.* at P 35.

503. *Id.* at P 35.

504. *Interstate Power and Light Co. v. ITC Midwest, L.L.C.*, 127 F.E.R.C. ¶ 61,043 (2009).

Interstate failed to establish that ITC Holdings' "use of the Massachusetts Formula to allocate non-direct A&G expenses to [ITC Midwest] is unjust and unreasonable."[505] The FERC denied the relief requested in Interstate's complaint without prejudice to Interstate's filing another complaint that adequately substantiates its allegations.[506] At year end the case was pending on rehearing.

On May 8, 2009, the FERC dismissed a complaint under FPA sections 206 and 306 submitted by Cottonwood Energy Company, L.P. (Cottonwood) against Entergy Gulf seeking recovery of an alleged overpayment to Entergy for construction of interconnection facilities.[507] Cottonwood, the owner of a 1,200 MW combined cycle electric facility interconnected to Entergy's transmission system, alleged that, under the terms of the interconnection agreement between the parties, Entergy owed Cottonwood for a tax gross-up overpayment Cottonwood made to Entergy for construction of certain interconnection facilities. The complaint requested relief in the form of an immediate refund of the alleged overpayment or, alternatively, immediate transmission credits in lieu of a refund. The FERC found that the interconnection agreement expressly and clearly provides that Cottonwood is entitled to a refund of a tax gross-up overpayment "only after Entergy has received the refund or credit from the IRS for any overpayment of taxes by Entergy," which had not yet occurred, and thus was not entitled to an immediate refund or immediate transmission credits.[508]

On July 14, 2009, the FERC denied a complaint under FPA sections 206 and 306 filed by the Arkansas Public Service Commission (Arkansas Commission) against Entergy seeking modification of certain text in Entergy's system agreement relating to the formula for bandwidth calculations it used to maintain the rough equalization of production costs among Entergy's utility subsidiaries.[509] The Arkansas Commission alleged that certain language in the system agreement is unjust and unreasonable because it has been construed by some parties as providing the FERC with authority to substitute imputed depreciation and decommissioning expenses for actual expenses approved by retail regulators as inputs for the calculation of the rough production cost equalization bandwidth. The FERC found that the "language at issue is appropriate and consistent with the [FERC's] authority under the FPA" because the "authority to determine the payments under the bandwidth necessarily must include the ability to examine the inputs used to calculate the bandwidth."[510] At year end the case was pending on rehearing.

XII. OTHER

A. Simultaneous Import Limit for Southeast Region

With its decision in *Carolina Power & Light Company*,[511] FERC put to rest a long-running controversy over the development of Simultaneous Transmission

505. *Id.* at PP 42-46.
506. *Id.* at PP 1, 46.
507. *Cottonwood Energy Co. v. Entergy Gulf States, Inc.*, 127 F.E.R.C. ¶ 61,128 (2009).
508. *Id.* at P 19.
509. *Ark. Pub. Serv. Comm'n v. Entergy Corp.*, 128 F.E.R.C. ¶ 61,020 (2009).
510. *Id.* at P 25.
511. *Carolina Power & Light Co.*, 128 F.E.R.C. ¶ 61,039 (2009).

Import (SIL) studies employed in the development of updated market power analyses filed by a group of Southeastern utilities pursuant to Order No. 697.[512]

These studies are employed in assessing each study area's import capability from associated first-tier areas in order to evaluate sellers' potential market power. The order rejected the Southeastern utilities' SIL studies, and instead substituted the Commission's own study results. Observing the divergent SIL values submitted by each of the Southeastern utilities in initial filings, and in each of two rounds of data responses to Staff requests, the Commission concluded that the utilities failed to reflect OASIS practices historically used by the study area and aggregated first-tier balancing authority areas, as directed by Order No. 697 and subsequent decisions.[513] To correct for the identified shortcomings, the FERC instead undertook its own study relying on Seasonal OASIS Studies undertaken by the Southeastern Electric Reliability Council (SERC).[514] More specifically, adjustments were made using the seasonal model and associated contingency file and monitored element files associated with the SERC Seasonal OASIS Studies.

B. Back-Stop Siting Filings

Section 1221(a) of the Energy Policy Act of 2005 (EPAct),[515] which added new FPA section 216, gave the Commission the authority to issue permits for the construction of electric transmission facilities in Department of Energy-designated transmission corridors in certain circumstances, including where a regulatory commission with siting authority over the facilities withheld approval of the facilities for more than one year after the submission of the application.[516] In implementing this law, the Commission determined that a state's denial of a construction request constituted a withholding of approval under the statute.[517] In 2008, SCE, citing the Arizona Corporation Commission's denial of SCE's request for authorization to construct the Arizona portion of the Devers-Palo Verde 2 transmission line, submitted the first pre-filing request to the Commission under this law.[518] On May 18, 2009, SCE withdrew its pre-filing request, citing an updated economic analysis.[519] As of year-end 2009, no other FPA section 216 applications or pre-filing requests had been submitted to the Commission.

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512. Order No. 697, *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, F.E.R.C. STATS. & REGS. ¶ 31,252 (2007) (*clarified*, 121 F.E.R.C. ¶ 61,260 (2007)), *order on reh'g*, Order No. 697-A, F.E.R.C. STATS. & REGS. ¶ 31,268 (2008), (clarified in 124 F.E.R.C. ¶ 61,055 (2008)), *order on reh'g*, Order No. 697-B, F.E.R.C. STATS. & REGS. ¶ 31,285 (2008), Order No. 697-C, F.E.R.C. STATS. & REGS. ¶ 31,291 (2009).

513. 128 F.E.R.C. ¶ 61,039 at PP 4 - 7.

514. *Id.* at P 8.

515. Pub. L. No. 109-58, 119 Stat. 594 (2005).

516. Order No. 689, *Regulations for Filing Applications for Permits to Site Interstate Electric Transmission Facilities*, F.E.R.C. STATS. & REGS. ¶ 31,234 at PP 3-4 (2006).

517. *Id.* at PP 24-34. The United States Court of Appeals for the Fourth Circuit reversed this ruling, holding that a state's denial of a construction request did not constitute withholding approval. Piedmont Envtl. Council v. FERC, 558 F.3d 304, 309-10 (4th Cir. 2009).

518. *Southern California Edison Co.*, *Request to Initiate Pre-filing Review Process for Devers-Palo Verde No. 2 Project*, Docket No. PT08-1-000 (May 16, 2008).

519. *Southern California Edison Co.*, *Notice of Withdrawal of Pre-filing Request*, Docket No. PT08-1-000 (May 18, 2009).

C. FERC/CFTC Jurisdiction over RTO/ISO Financial Products

Legislation being considered at the close of 2009 raised concerns of conflict and supplanting FERC jurisdiction with exclusive Commodities Futures Trading Commission (CFTC) jurisdiction over "financial" products created by RTOs/ISOs, including Financial Transmission Rights and Virtual Energy Transactions. These concerns arose from early drafts of The Over-the-Counter Derivatives Market Act of 2009,[520] the Administration's proposed legislative fix for failures in financial regulation viewed as contributing to the financial crises and ongoing recession of 2008-2009. After hearings were held at which Chairman Wellinghoff and industry representatives testified as to the need for modifications to the legislation to preserve FERC jurisdiction, the House of Representatives passed its version of the Bill with the requested protections.[521] A second issue of concern to the industry was the Bill's requirement that over-the-counter-derivative contracts (OCTDs), which could be interpreted to include hedging contracts on future energy prices, be effected only through a financially regulated clearing agency and be subject to various CFTC regulatory processes including the establishment of margin requirements. This issue was also addressed at the above hearings and with language inserted in the House passed Bill permitting the CFTC to exempt such contracts from the Bill's requirements.[522]

520. H.R. 3795, 111th Cong. (2009).

521. Wall Street Reform and Consumer Protection Act, H.R. 4173, 111th Cong. (2009). Impacts of H.R. 3795 – *The Over-the-Counter Derivatives Market Act of 2009*, Hearings of the SubCommittee on Energy & the Environment, Committee on Energy & Commerce, 111th Cong. (2009), *available at* http://energycommerc.house.gov/index.php?option=com_content&view=article&id=1838:impacts-of-hr-3795-the-over-the-counter-derivitives-market-act-of-2009-on-energymarkets&cati=130:subcommittee-on-energy-and-the-environmental&itemid=71.

522. *Id.*

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