REPORT OF THE ELECTRICITY REGULATION COMMITTEE

This report covers significant electric regulatory orders issued by the Federal Energy Regulatory Commission (FERC or the Commission) in 2014.* This report does not, however, address transmission reliability, demand-side management/renewable energy, FERC enforcement matters, or appellate decisions.

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I. RULEMAKINGS AND POLICY STATEMENTS

A. Coordination of the Scheduling Process of Interstate Natural Gas Pipelines and Public Utilities, 146 F.E.R.C. ¶ 61,201 (2014)

On March 20, 2014, the FERC issued a Notice of Proposed Rulemaking to revise its regulations to better coordinate the scheduling of natural gas and electricity markets, in light of increased reliance on natural gas for electric generation, and to provide additional flexibility to all shippers on interstate natural gas pipelines.[1] The FERC's proposal focuses on the scheduling practices of the natural gas transportation and electricity markets. In particular, the proposed rule would (1) start the natural gas operating day earlier "to ensure that gas-fired generators are not running short on gas supplies during the morning electric ramp periods;" (2) "[s]tart the first day-ahead gas nomination opportunity . . . for pipeline scheduling later than the current [start time] . . . to allow electric utilities to finalize their scheduling before gas-fired generators must make gas purchase arrangements and submit nomination requests for natural gas transportation service to the pipelines;" and (3) "[m]odify the current intraday nomination timeline to provide four intraday nomination cycles, instead of the existing two, to provide greater flexibility to all pipeline shippers."[2] The FERC also clarified its policy on the ability of a pipeline to permit firm shippers to bump an interruptible shipper's nomination during any enhanced nomination opportunity.[3] In addition, the FERC "propose[d] to require all interstate pipelines to offer multi-party services agreements" that can provide "multiple shippers the flexibility to share interstate pipeline capacity to serve complementary needs."[4] The FERC provided the natural gas and electric industries, through the North American Energy Standards Board, 180 days "to reach consensus on any revisions to the . . . proposed rule" and either file consensus standards or notify the FERC that a consensus could not be reached.[5]

1. *Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities*, 146 F.E.R.C. ¶ 61,201 at PP 1-2 (2014).

2. *Id.* at P 8.

3. *Id.* at P 73.

4. *Id.* at P 9.

5. *Id.* at P 10.

B. Refinements to Policies and Procedures for Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities, 147 F.E.R.C. ¶ 61,232 (2014)

On June 19, 2014, the FERC issued a Notice of Proposed Rulemaking to revise its policies, set forth in Order No. 697, for evaluating applications to sell energy, capacity, and related services at market-based rates (MBR).[6] The FERC stated that its proposed revisions were intended "to streamline and simplify the [MBR] program, and to enhance and improve the program's processes and procedures."[7] The proposals included new exemptions from the FERC's horizontal market power screen requirements and clarifications designed to bring the MBR program up to date with best practices.[8]

The FERC proposal no longer required applicants and sellers in markets operated by a regional transmission organization (RTO) or an independent system operator (ISO) to submit indicative horizontal market power screens: the pivotal supplier analysis and the wholesale market share analysis.[9] The FERC noted that its practice had been to grant exceptions to sellers in RTO markets that failed the screens and that the proposed exemption from filing the indicative screens is, therefore, intended to "modify the approach taken in Order No. 697 to reflect current practice and reduce the burden on these sellers."[10]

The FERC also proposed an exception "where all generation capacity owned or controlled by a seller and its affiliates in the relevant balancing authority areas (including first-tier balancing authority areas or markets) is fully committed."[11] The FERC requires sellers submitting the indicative screens to deduct committed generating capacity from uncommitted generating capacity, meaning that if a seller has only committed generating capacity, then the exercise becomes a "purely mathematical task" that nets out to zero.[12] Accordingly, the FERC proposed to exempt from the indicative screen requirements sellers who submit proof that their generating capacity in the relevant geographic market and first-tier markets is fully committed.[13] To demonstrate that their relevant capacity is fully committed, applicants must submit information detailing "the amount of generation capacity that is fully committed, the names of the counterparties, the length of the long-term contract, the expiration date of the contract, and a representation that the contract is for firm sales for one year or longer."[14]

To reduce administrative burdens on sellers, the FERC proposed eliminating the requirement that sellers provide reports on land acquisitions and sites for generation capacity development in MBR applications and triennial updated

6. *Refinements to Policies and Procedures for Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, 147 F.E.R.C. ¶ 61,232 (2014).

7. *Id.* at P 10.

8. *Id.*

9. *Id.* at P 36.

10. *Id.* at PP 34-35.

11. 147 F.E.R.C. ¶ 61,232 at P 11.

12. *Id.* at P 43.

13. *Id.*

14. *Id.* at P 44.

market power analyses.[15] The FERC reasoned that these requirements were unnecessary for the vertical market power analysis because no challenges resulted from these disclosures during the six years since they were first required.[16] The FERC also stated that its website clarifies how corporate families may file joint master tariffs through designated filers.[17] The FERC also proposed the creation of a new pre-programmed electronic spreadsheet to help sellers avoid errors in preparing affiliated asset appendices.[18]

To enhance transparency and the quality of publicly available information, the FERC proposed that sellers with energy-limited generation facilities, including solar, hydroelectric, and wind projects, may use regional capacity factor estimates appropriate to their specific technology as provided by the Energy Information Administration (EIA) in addition to nameplate, season, or five-year historical average figures for generating capacity.[19] The FERC reasoned that some newer facilities may not have five-year data available, and that the FERC has allowed such sellers to use the EIA regional capacity factors anyway.[20] The FERC emphasized that whatever method a seller uses to measure capacity, it must use the same method throughout an MBR application.[21] With respect to solar power, the FERC sought comment on "whether using peak hours will provide a better measure of capacity for photovoltaic solar, as compared to all hours," which would include hours during which the output would be zero.[22]

The FERC further proposed to require sellers to report long-term firm purchases of power in their screens and asset appendices whenever the purchaser has an associated long-term firm transmission reservation.[23] This proposal applies to sellers regardless of whether they have "operational control over the generation capacity supplying the purchased power."[24] The FERC explained that this proposal was intended to remedy the errors caused by "limited reporting of long-term firm purchases" revealed over the course of "two complete rounds of regional reviews."[25] The FERC noted that previously, capacity was routinely not being claimed by parties involved in long-term firm purchases, essentially distorting the FERC's estimation of the size of the market.[26] The FERC proposed to attribute this power to the purchasers, "because long-term firm power purchase agreements, including long-term firm energy agreements, provide the purchaser with energy that only can be interrupted for limited and specified reasons."[27]

15. *Id.* at P 89.
16. 147 F.E.R.C. ¶ 61,232 at P 90.
17. *Id.* at P 143.
18. *Id.* at P 63.
19. *Id.* at P 69.
20. *Id.* at P 68.
21. 147 F.E.R.C. ¶ 61,232 at P 71.
22. *Id.* at P 70 (emphasis omitted).
23. *Id.* at P 79.
24. *Id.*
25. *Id.* at P 75.
26. 147 F.E.R.C. ¶ 61,232 at P 76.
27. *Id.* at P 77.

The FERC also proposed to modify the relevant geographic market for an independent power producer (IPP) in a generation-only balancing authority area.[28] The FERC stated that, in contrast to franchised public utilities, which are usually under an obligation to serve a particular geographic region where they also own generation assets, the typical IPP "does not have a franchised service territory, or an obligation to serve retail customers."[29] Therefore, the FERC proposed expanding "the default relevant geographic market(s) for such a seller [to include] the balancing authority areas of each transmission provider to which its generation-only balancing authority area is directly interconnected."[30]

The FERC explained that changing the default relevant geographic market would require an IPP to study and submit screens for any uncommitted generating capacity in the balancing authority area where its generating assets are physically located, as well as any directly interconnected area with a transmission provider.[31] The FERC proposed that, if the IPP is directly interconnected to a trading hub, it should be required to study its uncommitted generating capacity as applied to all transmission providers in the hub.[32] The FERC limited this proposal to the balancing authority areas of the transmission providers themselves; therefore, an IPP would not be required to study any transmission provider's first-tier balancing authority area.[33]

Similarly, the FERC proposed to consider, for purposes of determining whether a seller qualifies as Category 1 or Category 2, all affiliated generation capacity in a given region for power marketers (sellers who do not own generation or transmission assets), whereas power producers (sellers who own generation or transmission assets) should report only the affiliated generation in the same region as the owned assets.[34] The FERC reasoned that power marketers have no home markets and are equally likely to make sales in any region, whereas power producers will presumably make the majority of their sales in the region in which their assets are located.[35]

To further increase transparency, the FERC proposed to allow MBR applicants and sellers to aggregate their behind-the-meter generation and qualifying small power production facilities under 20 mega-watt (MW), by balancing authority area or market into one line on the seller's asset appendix.[36] In addition, the FERC proposed requiring MBR applicants to file organizational charts detailing their corporate structure[37] and establish a publicly available, searchable database of the information submitted in MBR sellers' asset appendices.[38]

28. *Id.* at P 52.
29. *Id.* at P 51.
30. *Id.* at P 52.
31. 147 F.E.R.C. ¶ 61,232 at P 53.
32. *Id.* at P 56.
33. *Id.*
34. *Id.* at P 130.
35. *Id.*
36. 147 F.E.R.C. ¶ 61,232 at P 107.
37. *Id.* at P 136.
38. *Id.* at P 126.

II. RTO/ISO DEVELOPMENTS

A. *ISO New England, Inc.*

1. ISO New England Inc. & New England Power Pool, 147 F.E.R.C. ¶ 61,172 (2014)

On May 30, 2014, the FERC issued an order rejecting alternate proposals, submitted by ISO New England Inc. (ISO-NE) and New England Power Pool (NEPOOL) Participants Committee, to revise ISO-NE's Transmission, Markets and Services Tariff.[39] Each proposal was intended to address fleet-wide resource performance problems in New England.[40] ISO-NE's proposal contained significant changes to the Forward Capacity Market (FCM) design and "NEPOOL's proposal involve[d] incremental changes to the energy and ancillary services market and the FCM while largely maintaining the existing FCM rules."[41] The FERC instituted a proceeding under section 206 of the Federal Power Act (FPA), finding that ISO-NE's existing tariff was unjust and unreasonable, and requiring ISO-NE to (1) submit a modified version of its proposal to revise the FCM design, and (2) adopt the increased Reserve Constraint Penalty Factors from NEPOOL's proposal.[42]

As a threshold matter, the FERC found that ISO-NE's existing tariff, specifically the FCM rules, were unjust and unreasonable because they failed to provide adequate incentives for resource performance, thereby threatening reliable operation of the system and "forcing consumers to pay for capacity without receiving commensurate reliability benefits."[43] The FERC further found that the existing payment features of the FCM not only failed to incent resource performance but also selected "less reliable resources over more reliable resources because a capacity supplier's decision to forego investments that would improve resource performance" would allow the supplier to offer into the forward capacity auction (FCA) at a lower price.[44]

The FERC found that neither ISO-NE's nor NEPOOL's proposal, standing alone, had been shown to be a just and reasonable solution to the region's resource performance problems.[45] ISO-NE's proposal sought to address resource performance problems by implementing a two-settlement capacity market design, which ISO-NE described as a "Pay for Performance" market design, that links capacity revenues to resource performance during reserve deficiencies.[46] Under ISO-NE's proposed two-settlement process, a capacity resource's total capacity revenue is comprised of a Capacity Base Payment, established through the FCA, and a Capacity Performance Payment, determined by measuring each resource's

39. *ISO New England Inc.*, 147 F.E.R.C. ¶ 61,172 at P 1 (2014).

40. *Id.*

41. *Id.*

42. *Id.* at PP 1, 23.

43. *Id.* at PP 23, 26.

44. 147 F.E.R.C. ¶ 61,172 at P 26.

45. *Id.* at P 1.

46. *Id.* at P 4.

real-time performance against its forward position.[47] The FERC found that ISO-NE's two-settlement capacity market design generally represented "a just and reasonable approach to addressing resource performance concerns in [New England]."[48] However, the FERC found that ISO-NE's proposal to change the FCM payment design unduly discriminated against energy efficiency resources because those resources do not actively perform in real-time and, therefore, would be unable to respond to the proposal's performance incentive.[49] The FERC also found that, in the event of an intra-zonal transmission constraint, the Capacity Performance Payment could potentially lead to improper price signals that could prevent ISO-NE from efficiently dispatching resources.[50] Further, the FERC found that ISO-NE's proposal did not respond to the region's resource performance problems with the requisite speed and, therefore, did not represent a just and reasonable solution standing alone.[51]

In contrast to ISO-NE's proposal, NEPOOL's proposal sought to address resource performance problems by proposing (1) a new FCM performance metric for measuring "availability" (the Equivalent Peak Period Forced Outage Rate, or EFORp metric) and (2) "increased Reserve Constraint Penalty Factors to improve scarcity pricing in the real-time markets."[52] The FERC determined that NEPOOL's proposed EFORp metric was flawed because it measured a resource's performance only against its own historical performance, and, therefore, could "inappropriately reward poorly-performing resources and penalize highly-performing resources," further "erod[ing] reliability in the region."[53] However, the FERC found that the increased Reserve Constraint Penalty Factors in NEPOOL's proposal would incrementally improve real-time price signals, thereby providing "an increased incentive for resources to perform in real-time" that could be implemented immediately.[54] However, the FERC also found that this alone would not "provide a sufficient incentive to fully address the region's resource performance problems" or "correct the fundamental flaws in the FCM design."[55]

While the FERC determined that neither ISO-NE's proposal nor NEPOOL's proposal had been shown to be just and reasonable on its own, the FERC found that NEPOOL's proposed Reserve Constraint Penalty Factors, in combination with a modified version of ISO-NE's proposal, represented a just and reasonable solution.[56] Thus, the FERC directed ISO-NE to submit a compliance filing with tariff revisions to (1) "implement its two-settlement capacity market design" with certain modifications to address potential improper price signals and the discriminatory treatment of energy efficiency resources, and (2) "increase the Reserve Constraint Penalty Factors for 30-minute operating reserves to $1,000

47. *Id.* at PP 5-6.

48. *Id.* at P 36.

49. 147 F.E.R.C. ¶ 61,172 at P 89.

50. *Id.* at PP 23, 65.

51. *Id.*

52. *Id.* at PP 11, 24.

53. *Id.*

54. 147 F.E.R.C. ¶ 61,172 at P 24.

55. *Id.*

56. *Id.* at P 107.

[per mega-watt hour (MWh)] and for 10-minute non-spinning reserves to $1,500/MWh."[57]

2. ISO New England Inc., 149 F.E.R.C. ¶ 61,009 (2014)

On July 14, 2014, ISO-NE submitted a compliance filing in response to the FERC's directive for ISO-NE to increase the Reserve Constraint Penalty Factors in its real-time markets and implement a modified version of its proposed two-settlement capacity market design.[58] On October 2, 2014, the FERC issued an order conditionally accepting in part and rejecting in part ISO-NE's compliance filing and directing a further compliance filing.[59]

ISO-NE's compliance filing included tariff revisions intended to:

> (1) incorporate the higher Reserve Constraint Penalty Factors; (2) reflect a modified version of the two-settlement capacity market design to ensure that Capacity Performance Payments for energy efficiency resources are calculated only for Capacity Scarcity Conditions that occur during hours in which demand reduction values are calculated [for those resources]; and (3) address the [FERC's] concern regarding improper price signals that can arise from binding intra-zonal transmission constraints.[60]

The FERC accepted ISO-NE's Tariff revisions to increase the Reserve Constraint Penalty Factors for 30-Minute Operating Reserves from $500/MWh to $1,000/MWh and 10-Minute Non-Spinning Reserves from $850/MWh to $1,500/MWh, effective December 3, 2014.[61] The FERC found that these revisions complied with the compliance directive in the May 30, 2014 Order.[62] The FERC also agreed with ISO-NE that the Capacity Performance Payment Rate and the dynamic de-list bid threshold did not need to be adjusted as a result of the increased Reserve Constraint Penalty Factors.[63]

The FERC further accepted, subject to condition, ISO-NE's compliance proposal to set the Capacity Performance Score at zero for an energy efficiency resource during any Capacity Scarcity Condition outside of the resource's measured hours, effective June 1, 2018.[64] The FERC found that this proposal complied with the FERC's directive by ensuring that "energy efficiency resources will not be subject to Capacity Performance Payments outside those resources' measured hours."[65]

However, the FERC "reject[ed] ISO-NE's compliance proposal concerning improper price signals caused by binding intra-zonal transmission constraints."[66] The FERC found that, based on the record now before it, the improper price signal

57. *Id.* at PP 27, 62, 85.

58. *ISO New England Inc.*, 149 F.E.R.C. ¶ 61,009 (2014), *reh'g pending*; *see also ISO New England Inc.*, 147 F.E.R.C. ¶ 61,172 (2014).

59. 149 F.E.R.C. ¶ 61,009 at P 1.

60. *Id.* at P 7.

61. *Id.* at P 23.

62. *Id.*

63. *Id.* at PP 24-28.

64. 149 F.E.R.C. ¶ 61,009 at P 33.

65. *Id.* at P 33.

66. *Id.* at P 56.

problem the FERC identified in the May 30, 2014 Order was limited in scope.[67] The FERC stated that ISO-NE provided additional information indicating that the "intra-zonal transmission constraints in the New England region that result in potential problematic improper price signals are of limited geographic scope," and other parties submitted additional information indicating that the incentive for capacity resources to submit energy market offers "below their actual marginal costs is weaker than contemplated by the [FERC]."[68] Thus, the FERC directed ISO-NE to submit a further compliance filing removing the language reflecting this aspect of the compliance proposal and conforming these tariff sections to the language ISO-NE proposed in its original filing.[69]

3. ISO New England Inc., 147 F.E.R.C. ¶ 61,173 (2014)

On May 30, 2014, the FERC conditionally accepted ISO-NE and NEPOOL's proposed revisions to the ISO-NE Tariff to: (1) replace the vertical demand curve in ISO-NE's FCM with a system-wide sloped demand curve; (2) extend, from five years to seven years, the period for which a new resource may elect to receive the clearing price established in the initial FCA in which it participates; (3) establish a limited exception to the minimum offer price requirement for certain renewable resources; and (4) eliminate system-wide administrative pricing rules.[70] The FERC accepted ISO-NE's proposed demand curve changes, under which the demand curve is determined based on "(1) the estimated gross cost of entry (CONE) for a new capacity resource; (2) the estimated CONE net of revenues from energy, reserve, and other markets (net CONE); and (3) well-established system planning design criteria for resource adequacy . . . based on loss of load expectations calculations (LOLE)."[71] In particular, the demand curve is set "at 1.6 times the net CONE at the supply quantity needed to provide a 1-in-5 LOLE level of reliability."[72] In accepting the proposed curve, the FERC rejected concerns that the selection of a combined-cycle combustion turbine as reference technology, reasoning that the goal of a proxy unit is intended to elicit an amount of capacity sufficient to ensure reliability.[73]

The FERC also accepted ISO-NE and NEPOOL's proposal to remove system-wide administrative pricing rules but leave in place zonal administrative pricing rules, as the parties committed to implementing sloped zonal demand curves by the time of the February 2015 FCA.[74] The FERC additionally accepted an extension, from five to seven years, of the period during which a new capacity resource can lock-in the price established in the resource's initial FCA.[75] The FERC explained that this price lock-in provision is "directly correlated with the sloped demand curve," and the longer lock-in period achieved "a reasonable

67. *Id.* at PP 56-57.

68. *Id.* at P 57.

69. 149 F.E.R.C. ¶ 61,009 at P 56.

70. *ISO New England Inc.*, 147 F.E.R.C. ¶ 61,173 at PP 1, 5 (2014).

71. *Id.* at PP 1, 13. LOLE "refers to the probability of disconnecting non-interruptible customers due to a resource deficiency." *Id.* at P 13 n.11.

72. *Id.* at P 13.

73. *Id.* at P 32.

74. 147 F.E.R.C. ¶ 61,173 at PP 40-41.

75. *Id.* at P 57.

balance between incenting new entry and protecting consumers from high prices."[76] The FERC found that such an extension provides investor assurance and, although the price lock-in creates a lower market-clearing price, other demand curve parameters help to assure adequate new and existing resources.[77]

Further, the FERC accepted ISO-NE and NEPOOL's proposal to allow an exemption from the minimum offer price requirement for certain resources that qualify as Renewable Technology Resources.[78] The FERC rejected concerns that the exemption would cause price suppression or lead to certain self-supply opportunities or differing state renewable portfolio standards having a discriminatory impact on certain resources.[79]

4. ISO New England Inc., 148 F.E.R.C. ¶ 61,179 (2014)

On September 9, 2014, the FERC accepted ISO-NE and NEPOOL's proposed tariff changes to implement a Winter Reliability Program for the 2014-2015 winter.[80] The Winter Reliability Program is intended to help maintain winter reliability by (1) creating incentives for dual-fuel resources to carry sufficient oil and LNG, (2) creating incentives for installing dual-fuel capability, and (3) providing compensation to demand response resources.[81] In addition, ISO-NE proposed market-monitoring changes designed to provide greater operational flexibility for dual-fuel generators participating in the program.[82] The FERC accepted the Winter Reliability Program, but directed ISO-NE to initiate a stakeholder process to develop and propose a long-term, market-based solution to address winter reliability concerns in the 2015-2016 winter and future winters, as necessary.[83]

B. PJM Interconnection, L.L.C.

1. PJM Interconnection, L.L.C., 149 F.E.R.C. ¶ 61,091 (2014)

On October 31, 2014, the FERC approved tariff revisions proposed by PJM Interconnection, L.L.C. (PJM) to permit only frequently mitigated generation units (Frequently Mitigated Units) that the market monitor determines are unable to recover their going-forward costs to receive Offer Price Adders.[84] Due to the evolution of PJM's market mechanisms, such as its capacity market auctions, the FERC agreed with PJM and several interveners that the existing Offer Price Adders for Frequently Mitigated Units had become unjust and unreasonable.[85] In particular, the FERC stated that Offer Price Adders were originally designed to afford units an opportunity to recover their going-forward costs, which many units

76. *Id.* at PP 54-56.
77. *Id.* at P 56.
78. *Id.* at P 81.
79. 147 F.E.R.C. ¶ 61,173 at PP 82-83.
80. *ISO New England Inc.*, 148 F.E.R.C. ¶ 61,179 at P 1 (2014).
81. *Id.* at P 2.
82. *Id.* at P 12.
83. *Id.* at P 1.
84. *PJM Interconnection, L.L.C.*, 149 FERC ¶ 61,091 at PP 2, 6 (2014).
85. *Id.* at P 30.

now recover through participation in PJM's markets.[86] As a result, the FERC noted that PJM's existing Offer Price Adders had come to operate as windfalls to some Frequently Mitigated Units.[87]

Among other arguments, the FERC rejected the assertion that, according to precedent, Offer Price Adders are designed to cover more than a generator's going-forward costs.[88] The FERC held that Offer Price Adders should appropriately cover the marginal cost of a unit in the short run.[89] The FERC further stated that it would be inappropriate for a Frequently Mitigated Unit to receive a guaranteed margin of recovery beyond its going-forward or marginal costs and that its finding was consistent with prior FERC orders.[90]

C. Midcontinent Independent System Operator, Inc.

1. Midwest Independent Transmission System Operator, Inc., 148 F.E.R.C. ¶ 61,204 (2014)

On September 18, 2014, the FERC conditionally accepted Midwest Independent Transmission System Operator, Inc.'s (MISO)[91] proposed revisions to its Open Access Transmission, Energy, and Operating Reserve Markets Tariff concerning Multi-Value Project (MVP) Auction Revenue Rights (ARRs), subject to a compliance filing.[92] The FERC found that MISO's proposal to allocate MVP ARRs on a regional basis in Stage 1B, after prioritizing the feasibility of long term transmission rights (LTTRs) in Stage 1A, was just and reasonable, not unduly discriminatory or preferential, and in compliance with the FERC's 2010 directive to MISO on this subject.[93] The FERC rejected assertions that MISO's portfolio approach was unduly discriminatory or preferential because (1) "MVPs will be situated throughout the MISO footprint," (2) "MVP [benefits] will accrue throughout the MISO footprint," and (3) "MISO's proposed allocation of LTTRs in Stage 1A . . . balances the interests of market participants that use short-term transmission contracts with [the interests] of the load-serving entities that use long-term contracts."[94] The FERC also found that MISO's proposal provided an opportunity for all entities that incurred MVP costs to realize MVP-related benefits in Stage 1A and that any costs incurred under Schedule 39 or other "MVP-related schedules," qualify for associated credits in Stage 1B.[95] Finally, the FERC

86. *Id.* at P 32.

87. *Id.*

88. *Id.* at P 36.

89. 149 F.E.R.C. ¶ 61,091 at P 36.

90. *Id.* (citing *PJM Interconnection, L.L.C.*, 110 F.E.R.C. ¶ 61,053 at P 114 (2005)).

91. Effective April 26, 2013, MISO changed its name from "Midwest Independent Transmission System Operator, Inc." to "Midcontinent Independent System Operator, Inc."

92. *Midwest Indep. Transmission Sys. Operator, Inc.*, 148 F.E.R.C. ¶ 61,204 at P 1 (2014).

93. *Id.* at P 40 (citing *Midwest Indep. Transmission Sys. Operator, Inc.*, 133 F.E.R.C. ¶ 61,221 (2010) (MVP Order), *order on reh'g*, 137 F.E.R.C. ¶ 61,074 (2011) (MVP Rehearing Order), *aff'd in part and remanded in part sub nom*. Ill. Commerce Comm'n v. FERC, 721 F.3d 764 (7th Cir. 2013), *cert. denied*, Shutte v. FERC, No. 13-443, 82 U.S.L.W. 3240 (U.S. Feb. 24, 2014), Hoosier Energy Rural Elec. Co-Op., Inc. v. FERC, No. 13-445, 82 U.S.L.W. 3240 (U.S. Feb. 24, 2014)).

94. 148 F.E.R.C. ¶ 61,204 at PP 41-42.

95. *Id.* at PP 43-44.

directed MISO to make a compliance filing to (1) clarify its proposed tariff language to note that the Simultaneous Feasibility Test is used with regard to the allocation of ARRs, not just financial transmission rights, and (2) more specifically identify the "MVP-related schedules" referenced in MISO's proposed tariff language.[96]

2. Midcontinent Independent System Operator, Inc., 149 F.E.R.C. ¶ 61,114 (2014)

On November 10, 2014, the FERC conditionally accepted in part, terminated in part, and accepted and suspended in part, a proposed System Support Resource (SSR) Agreement between MISO and Wisconsin Electric Power Co. (Wisconsin Electric).[97] Under the MISO tariff, a market participant must submit notice of its decision to retire or suspend a generation resource at least twenty-six weeks prior to the retirement or suspension of service.[98] MISO will conduct a study during the twenty-six-week period and, if MISO determines (1) that "all or a portion of the resource's capacity is necessary to maintain system reliability," and (2) no alternative to an SSR can be implemented before the retirement or suspension of service, then MISO will enter into an SSR Agreement with the market participant to ensure that the resource continues to operate.[99] On September 12, 2014, MISO submitted a proposed SSR Agreement between MISO and Wisconsin Electric providing compensation for the continued availability of Wisconsin Electric's Presque Isle Units 5-9 as SSR units "for a 14.5-month term between October 15, 2014 and December 31, 2015."[100] MISO stated that this time period "should encompass most of the time needed to complete the engineering work necessary for compliance with the Environmental Protection Agency's [Mercury and Air Toxics Standards]."[101] In a related filing, also on September 12, 2014, MISO proposed revisions to Rate Schedule 43G to allow MISO to allocate the SSR costs associated with Presque Isle Units 5-9 to Load-Serving Entities (LSE) in certain Local Balancing Authorities (LBA), "based upon peak usage of transmission facilities in each month."[102]

The FERC found that MISO had justified the need for Presque Isle Units 5-9 as SSR units, accepting "MISO's explanation that four Presque Isle units are necessary due to both steady state and voltage stability operating limits, and one unit must be rotated offline to ensure unit maintenance and implement any necessary environmental retrofits."[103] In accepting the SSR Agreement, the FERC terminated an existing SSR agreement applicable to Presque Isle Units 5-9. However, the FERC found that the SSR compensation proposal in the SSR Agreement had not been shown to be just and reasonable.[104] Thus, the FERC

96. *Id.* at P 45.
97. *Midcontinent Indep. Sys. Operator, Inc.*, 149 F.E.R.C. ¶ 61,114 at P 1 (2014).
98. *Id.* at P 2.
99. *Id.*
100. *Id.* at P 9.
101. *Id.*
102. *Id.* at P 69.
103. 149 F.E.R.C. ¶ 61,114 at P 36.
104. *Id.* at P 67.

accepted and suspended the SSR Agreement, to become effective October 15, 2014, subject to refund, "and set all SSR compensation issues, including the cost-of-service, formula rate, and true-up procedures, for hearing and settlement judge procedures."[105] In addressing MISO's related filing to revise Rate Schedule 43G, the FERC explained that MISO's proposed cost allocation language implicates several issues in an ongoing, related SSR proceeding.[106] Accordingly, the FERC accepted and suspended MISO's revisions to Rate Schedule 43G, to be effective October 15, 2014, subject to refund and a further FERC order in the related SSR proceeding.[107]

3. Midcontinent Independent System Operator, Inc., 149 F.E.R.C. ¶ 61,095 (2014)

On October 31, 2014, the FERC conditionally accepted MISO's proposal to introduce a new ramp capability product, consistent with Order No. 764,[108] to manage variability in generation output more effectively.[109] The FERC found that allocation of costs to load and exports was appropriate.[110] The FERC also found that the lack of self-scheduling and a "Not Qualified" dispatch status was not discriminatory, and was otherwise appropriate for purposes of the product.[111] The FERC found that MISO's requirement that resources have "a Ramp Capability Dispatch status of 'Economic' (for both Up Ramp Capability and for Down Ramp Capability) to qualify for [Price Volatility Make-Whole Payments (PVMWP)] and Real-Time Revenue Sufficiency Guarantee (RTRSG) payments" was appropriate.[112] The FERC further found "resources that do not provide Ramp Capability Product . . . limit[] their dispatch flexibility, which would significantly undermine the PVMWP's objective."[113] The FERC directed MISO to add certain definitions to its tariff,[114] and clarify any limitations on the participation of Variable Energy Resources in providing the Ramp Capability Product.[115] The FERC also directed certain other clarifications and corrections of apparent "inadvertent" errors in tariff language, and explained how certain future actions in other dockets will affect this filing.[116]

105. *Id.* at P 53.

106. *Id.* at P 78.

107. *Id.*

108. Order No. 764, *Integration of Variable Energy Resources*, 77 Fed. Reg. 41,482 (2012), F.E.R.C. STATS. & REGS. ¶ 31,331, *order on reh'g*, Order No. 764-A, 141 F.E.R.C. ¶ 61,232 (2012), *order on reh'g*, Order No. 764-B, 144 F.E.R.C. ¶ 61,222 (2013).

109. *Midcontinent Indep. Sys. Operator, Inc.*, 149 F.E.R.C. ¶ 61,095 at PP 1, 3 (2014).

110. *Id.* at P 26.

111. *Id.* at P 37.

112. *Id.* at PP 38, 43.

113. *Id.* at P 43.

114. 149 F.E.R.C. ¶ 61,095 at P 50.

115. *Id.* at P 55.

116. *Id.* at PP 56-62.

D. Southwest Power Pool, Inc.

1. Southwest Power Pool, Inc., 149 F.E.R.C. ¶ 61,113 (2014)

On September 11, 2014, the FERC conditionally accepted in part, rejected in part, and accepted and suspended in part, Southwest Power Pool, Inc.'s (SPP) proposed revisions to its Open Access Transmission Tariff, Bylaws, and Membership Agreement (Governing Documents). SPP proposed to facilitate the decision of Western Area Power Administration–Upper Great Plains (Western-UGP), Basin Electric Power Cooperative (Basin Electric), and Heartland Consumers Power District (Heartland) (collectively, Integrated System Parties) "to join SPP as transmission owning members, to place their respective transmission facilities under the functional control of SPP, and to begin taking transmission service under the SPP [t]ariff."[117] The FERC summarily decided a handful of issues, but otherwise set SPP's proposed revisions for hearing and settlement judge procedures.[118]

The FERC granted SPP's request to establish a federal service exemption for the delivery of Western-UGP's resources to its statutory load obligations, explaining that Western-UGP's federal service exemption "is narrowly limited to apply only to the delivery of electric energy from Western-UGP resources to its statutory load customers to maintain Western's statutory responsibilities or obligations."[119] The FERC found SPP's proposed co-supply arrangement to be just and reasonable and consistent with FERC precedent in *Duke Power Co.*[120] With regard to regional charges for base plan upgrades that are not subject to the federal service exemption, the FERC found SPP's base plan upgrade and cost-sharing proposal to be just and reasonable.[121] The FERC explained that, "[t]here is no clear one-size-fits-all just and reasonable approach for such an integration. Rather, in order to find a proposal to be just and reasonable, the proposal must respect both the principle of cost causation and the practical realities of a transition."[122] In response to comments from multiple parties concerning seams issues related to the integration of the Integrated System Parties into SPP, the FERC set the seams issues for hearing and settlement judge procedures.[123] In doing so, the FERC recognized that "many utilities in this area have facilities that are highly integrated with each other as a result of joint planning and ownership of transmission, and that these arrangements may need to be reflected in their service arrangements with SPP."[124] The FERC conditionally accepted SPP's proposed revisions to the generator interconnection procedures in attachment V of its tariff, subject to a compliance filing to correct a reference in the interconnection

117. *Sw. Power Pool, Inc.*, 149 F.E.R.C. ¶ 61,113 at P 1 (2014).
118. *Id.* at P 17.
119. *Id.* at P 50.
120. *Id.* at P 59 (citing *Duke Power Co.*, 81 F.E.R.C. ¶ 61,010 (1997)).
121. *Id.*
122. 149 F.E.R.C. ¶ 61,113 at P 72.
123. *Id.* at P 112.
124. *Id.*

agreement and to confirm the appropriate treatment of interest when issuing refunds related to interconnection agreements.[125]

E. California Independent System Operator Corp.

1. California Independent System Operator Corp., 147 F.E.R.C. ¶ 61,231 (2014)

On June 19, 2014, the FERC conditionally accepted the California Independent System Operator Corporation's (CAISO) proposed revisions to its Open Access Transmission Tariff (OATT) to permit other balancing authority areas (BAA) in the western states to participate in a regional, real-time energy imbalance market (EIM).[126] The FERC accepted a majority of the CAISO's proposed changes, noting that, "addressing [the] imbalances in the West across a wider footprint can provide significant benefits[,]" including a savings to customers of "$21 to $129 million per year."[127] The regional EIM will be built upon the CAISO's existing real-time market, which will be expanded "to cover a broader geographical scope and to involve a larger number of participants."[128] Participation in the market will be voluntary for any BAA and any entity within each participating BAA.[129] Participants in the market will be able to buy and sell five-minute real-time energy in response to energy imbalances, with trading to begin October 1, 2014.[130]

As accepted by the FERC, the EIM will include four new roles. First, balancing authorities serving as "EIM Entities" are "responsible for identifying available transmission capacity in [the] BAA for use in the EIM" and "for scheduling all load and resources in [the] BAA that do not participate in the EIM."[131] Second, "[a]n EIM Entity Scheduling Coordinator is the entity through which an EIM Entity participates in the EIM."[132] Third, "EIM Participating Resources are the owners or operators of resources" participating in the market by bidding supply.[133] All resources that are eligible to participate in the CAISO's present real-time market may participate in the EIM, provided the resource meets the necessary technical requirements.[134] Fourth, an "EIM Participating Resource Scheduling Coordinator" is the entity that participating resources use to access the EIM.[135]

Because resources outside California will incur greenhouse gas (GHG) compliance costs if their energy is dispatched in California, the FERC accepted the CAISO's proposal to allow "EIM resources outside California to submit a bid adder with their energy bids to cover the costs of complying with California Air

125. *Id.* at P 125.
126. *Cal. Indep. Sys. Operator Corp.*, 147 F.E.R.C. ¶ 61,231 (2014).
127. *Id.* at PP 75-76.
128. *Id.* at PP 6-7.
129. *Id.* at P 8.
130. *Id.* at PP 2, 312.
131. 147 F.E.R.C. ¶ 61,231 at P 19.
132. *Id.* at P 20.
133. *Id.* at P 21.
134. *Id.*
135. *Id.* at P 22.

Resources Board's" regulations.[136] The FERC found that the GHG bid adder "will provide a reasonable avenue both for EIM Participating Resources to signal that they do not wish to be dispatched into California, and for EIM Participating Resources that are dispatched into California to recover the additional GHG compliance costs."[137]

The FERC also accepted the CAISO's proposal to "implement reciprocal transmission rates for EIM transfers," such that the CAISO "would not be assessed charges on transmission used for EIM transfers [from one EIM entity BAA to] other EIM Entity BAAs" and allowed the reciprocal transmission charging scheme.[138] The FERC noted that eliminating multiple transmission charges for power received over long distances inside a given market is regularly done by RTOs.[139] Given the parallel "enhanced efficiency and reliability" goals of the EIM and an RTO, the FERC approved the CAISO's proposal.[140]

The FERC did not accept all of the CAISO's proposals. While the FERC "decline[d] . . . to require real-time local market power mitigation on EIM interties at EIM start-up," it also rejected the CAISO's proposal to vest its board with discretion to implement these measures at its discretion in the future.[141] The FERC reasoned that, "[r]eal-time local market power mitigation on EIM interties affects clearing prices in the EIM and whether or not such mitigation is implemented should be subject to [FERC] review and approval."[142]

2. PacifiCorp, 147 F.E.R.C. ¶ 61,227 (2014)

On June 19, 2014, the FERC issued conditionally accepted in part and rejected in part PacifiCorp's proposed OATT revisions to facilitate PacifiCorp's participation in the CAISO's EIM.[143] The FERC found it appropriate for PacifiCorp's OATT to cross-reference the EIM provisions of the CAISO OATT "to ensure PacifiCorp's seamless integration into the EIM" and ruled that attachment T will control if conflict arises with the remainder of the PacifiCorp OATT.[144] The Commission accepted PacifiCorp's proposed OATT revisions to utilize firm transmission voluntarily offered by PacifiCorp's transmission customer, PacifiCorp Energy, but required that PacifiCorp make a compliance filing revising "Attachment T to include the requirements for scheduling and using transmission rights held by an Interchange Rights Holder."[145]

The FERC conditionally accepted PacifiCorp's proposal to allow generating resources that are not physically located in the PacifiCorp BAAs to file as EIM Participating Resources.[146] The FERC required PacifiCorp to submit a

136. 147 F.E.R.C. ¶ 61,231 at P 57.
137. *Id.* at P 238.
138. *Id.* at PP 125, 153.
139. *Id.* at PP 156-57.
140. *Id.* at P 155.
141. 147 F.E.R.C. ¶ 61,231 at P 219.
142. *Id.* at P 218.
143. *PacifiCorp*, 147 F.E.R.C. ¶ 61,227 (2014).
144. *Id.* at PP 101-02.
145. *Id.* at P 113.
146. *Id.* at P 130.

compliance filing to eliminate from its OATT the requirement that EIM Participating Resources pay for transmission service in addition to the transmission rates they incur as a PacifiCorp transmission customer.[147] The FERC conditionally accepted PacifiCorp's proposed changes to OATT Schedule 4, for Energy Imbalance Service, and Schedule 9, for Generator Imbalance Service, to settle energy imbalances using the EIM locational marginal price (LMP) for all of its customers, regardless of whether each customer participates in the EIM.[148] The FERC required PacifiCorp to revise Schedule 10 of its OATT "to financially settle losses using the full LMP in place of the Hourly Pricing Proxy," and required PacifiCorp to submit a compliance filing to clarify the language of Schedule 9 regarding the application of charges and payments to generators and the payment of the instructed imbalance energy price to non-participating EIM resources.[149]

The FERC approved PacifiCorp's proposed revisions of OATT Schedule 1, allowing the pass-through of several administrative fees and charges associated with participation in the EIM and directed PacifiCorp to document each EIM-related charge in its annual transmission formula rate filing.[150] The FERC accepted PacifiCorp's proposal to sub-allocate several CAISO "EIM Uplift Charges"[151] to its transmission customers on the basis of Measured Demand, and directed PacifiCorp to submit a report to the FERC fifteen months after the EIM go-live date to determine "whether continued use of the Measured Demand allocation is appropriate for the flexible ramping constraint charge."[152]

The FERC required PacifiCorp's transmission customers to submit forecast data to PacifiCorp, as the EIM Entity, which will in turn provide the data to the CAISO so it can model and account for expected load, generation, imports, and exports during the operating hour.[153] The FERC rejected PacifiCorp's proposal to have the authority to unilaterally suspend its participation in the EIM if design flaws were found during the first twelve months of EIM operation.[154]

The FERC directed PacifiCorp to make a market-based rate change-of-status filing in order for the FERC to assess whether PacifiCorp has market power in the EIM.[155] The FERC accepted PacifiCorp's proposed addition of OATT section 12.4A to address EIM Disputes that may arise in the administration and settlement of the EIM.[156] The FERC directed PacifiCorp to submit a compliance filing

147. *Id.* at P 113. The FERC required that this compliance filing be submitted within thirty days of the date of issuance of the FERC's order. *Id.*

148. 147 F.E.R.C. ¶ 61,227 at PP 150, 160.

149. *Id.* at P 162.

150. *Id.* at P 170.

151. *Id.* at P 73.

152. *Id.* at P 184.

153. 147 F.E.R.C. ¶ 61,227 at P 191.

154. *Id.* at P 196.

155. *Id.* at P 206. The FERC required this report be filed within nine months of the launch of the EIM market, and also required CAISO provide an informational status update to the FERC every six months for two years following the EIM go-live date. *Id.* at PP 206-07.

156. *Id.* at P 213.

incorporating several changes to the definitions section of its OATT and modifications to parts I through V of its OATT for EIM implementation.[157]

The FERC accepted PacifiCorp's proposal to use a dynamic e-Tag to implement EIM Transfers across the interface between BAAs, acknowledging that such a curtailment priority is consistent with the existing WECC Unscheduled Flow Mitigation Plan.[158] The FERC also determined that issues "regarding the effects of PacifiCorp's proposal on third party transmission rights are not ripe for resolution" until PacifiCorp submits a compliance filing "detailing the procedures for Interchange Rights Holders to transfer their transmission capacity to PacifiCorp for the EIM."[159]

III. TRANSMISSION RATES

A. Coakley, Massachusetts Attorney General v. Bangor Hydro-Electric Co., Opinion No. 531, 147 F.E.R.C. ¶ 61,234 (2014)

On June 19, 2014, the FERC affirmed in part and reversed in part an initial decision concerning the base return on equity (ROE) for a group of New England Transmission Owners (NETOs).[160] The proceeding was initiated as the result of a complaint filed in 2011 "alleging that the NETOs' 11.14[%] base ROE is unjust and unreasonable" as a result of significant changes in capital market conditions since the ROE was established.[161] In its order, the FERC established a new approach for determining public utilities' base ROEs.[162] The FERC found that changes to the electric utility industry make it appropriate to switch from the one-step discounted cash flow (DCF) methodology the FERC has traditionally used for public utilities to the two-step DCF methodology the FERC uses for natural gas and oil pipelines.[163]

The FERC explained that both DCF models use the same constant growth DCF formula to calculate an estimate of the base ROE required by investors to invest in a company: $k=D/P\ (1+.5g) + g$, "where 'P' is the price of the common stock, 'D' is the current dividend, 'k' is the discount rate (or investors' required rate of return), and 'g' is the expected growth rate in dividends."[164] The FERC explained that it has made changes over the years in its implementation of the DCF model with respect to the different industries it regulates.[165] Specifically, the FERC explained that the one-step DCF methodology historically applied to public utilities takes into account only short-term growth projections in estimating a company's cost of equity, while the two-step DCF methodology historically used

157. *Id.* at P 232. The FERC required this compliance filing be submitted within thirty days after the date of issuance of this order. *Id.* at P 97.

158. 147 F.E.R.C. ¶ 61,227 at P 217.

159. *Id.* at P 230.

160. *Coakley, Mass. Attorney Gen. v. Bangor Hydro-Elec. Co.*, Opinion No. 531, 147 F.E.R.C. ¶ 61,234 at P 1 (2014), *reh'g pending*.

161. *Id.* at P 3.

162. *Id.* at P 1.

163. *Id.* at PP 8, 39.

164. *Id.* at PP 14-15.

165. 147 F.E.R.C. ¶ 61,234 at P 16.

for natural gas and oil pipelines uses both long-term and short-term growth projections.[166]

The FERC explained that, under the two-step DCF methodology it is now adopting for public utilities, it "determines a single cost of equity estimate for each member of a proxy group,"[167] then "uses a two-step procedure for determining the constant dividend growth component of the model, averaging the short-term and long-term growth estimates . . . . The short-term forecast receives a two-thirds weighting and the long-term forecast receives a one-third weighting in calculating the growth rate in the DCF model."[168] The FERC specified that, "[t]he short-term growth estimate will be based on the five-year projections reported by IBES (or a comparable source)," and "the long-term growth estimate will be based on an average of the [gross domestic product] (GDP) growth rates that have been relied on in gas and oil pipeline cases."[169] Once the FERC has determined a single cost of equity estimate for each proxy group member, "the zone of reasonableness is defined by the low and high estimates of the market cost of equity for the members of the proxy group."[170]

The FERC explained that,

> [w]hile the DCF model remains the [FERC's] preferred approach to determining allowed rate of return, the [FERC] may consider the extent to which economic anomalies may have affected the reliability of DCF analyses in determining where to set a public utility's ROE within the range of reasonable returns established by the two-step constant growth DCF methodology.[171]

The FERC further stated that,

> [w]hile the [FERC] has previously found the midpoint of the zone of reasonableness to be the appropriate measure of central tendency for determining the base ROE for a diverse group of utilities (as opposed to the median, used for a single utility), the midpoint does not represent a just and reasonable outcome *if* the midpoint does not appropriately represent the utilities' risk.[172]

The FERC then applied the new two-step DCF methodology to the facts of the proceeding,[173] affirming the use of a national proxy group rather than a regional proxy group.[174] After determining a zone of reasonableness using the two-step DCF methodology, the FERC explained that it typically uses the midpoint of the zone of reasonableness to determine the base ROE for multiple entities, but concluded that in this case, a "mechanical application of the DCF methodology with the use of the midpoint here would result in an ROE that does not satisfy the requirements of *Hope* and *Bluefield*."[175] The FERC then determined that, the "base ROE for the NETOs should be set halfway between the midpoint

166. *Id.* at P 8.
167. *Id.* at P 17.
168. *Id.*
169. *Id.* at P 39.
170. *Id.* at P 23.
171. 147 F.E.R.C. ¶ 61,234 at P 41.
172. *Id.* at P 144.
173. *Id.* at P 9.
174. *Id.* at P 96.
175. *Id.* at P 142 (citing FPC v. Hope Natural Gas Co., 320 U.S. 591 (1944); Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n, 262 U.S. 679 (1923) (internal citations omitted)).

of the zone of reasonableness and the top of the zone of reasonableness."[176] The FERC tentatively found that, based on the record in the proceeding, the NETOs' base ROE should be set at 10.57%, "which is halfway between the 9.39[%] midpoint of the zone of reasonableness and the 11.74[%] top of that zone."[177]

The FERC explained that, because no party had presented evidence on the issues associated with the two-step DCF methodology at hearing, the parties had not litigated the issue of the appropriate source to use for long-term growth projections in the two-step DCF methodology.[178] The FERC used projections of long-term growth in GDP as the long-term growth projection, but reopened the record in the proceeding and established a paper hearing to allow the participants to present written evidence regarding the "appropriate long-term growth projection to be used for public utilities under the two-step DCF methodology."[179] The FERC explained that its finding that 10.57% is a just and reasonable base ROE for the NETOs was tentative because it is subject to the outcome of the paper hearing on the long-term growth projection.[180]

The FERC also changed its long-standing practice of updating the ROE within the zone of reasonableness at the time of its final decision based on changes in United States Treasury bond yields during the relevant time period.[181] The FERC explained that it was changing this practice because the record indicates "there is not a direct correlation between changes in U.S. Treasury bond yields and changes in ROE."[182]

Finally, the FERC addressed the impact that its application of the two-step DCF methodology has on existing ROE incentive adders. The FERC explained that the two-step DCF analysis will generally result in a narrower zone of reasonableness than would the one-step DCF methodology.[183] The FERC explained that, "when a public utility's ROE is changed . . . that utility's total ROE, inclusive of transmission incentive ROE adders, should not exceed the top of the zone of reasonableness produced by the two-step DCF methodology."[184]

B. Coakley, Massachusetts Attorney General v. Bangor Hydro-Electric Co., Opinion No. 531-A, 147 F.E.R.C. ¶ 61,032 (2014)

On October 16, 2014, the FERC issued an order on the paper hearing, initiated in Opinion No. 531,[185] to determine the appropriate long-term growth rate to use in the two-step DCF methodology for determining the base ROE for the NETOs.[186] The FERC determined "that the projected long-term growth in GDP

176. 147 F.E.R.C. ¶ 61,234 at P 142.
177. *Id.*
178. *Id.* at PP 42-43.
179. *Id.* at PP 43, 142, 154.
180. *Id.* at PP 142, 154.
181. 147 F.E.R.C. ¶ 61,234 at P 157.
182. *Id.* at P 158.
183. *Id.* at P 161.
184. *Id.* at P 165.
185. *Coakley, Mass. Attorney Gen. v. Bangor Hydro-Elec. Co.*, Opinion No. 531, 147 F.E.R.C. ¶ 61,234 (2014).
186. *Coakley, Mass. Attorney Gen. v. Bangor Hydro-Elec. Co.*, Opinion No. 531-A, 149 F.E.R.C. ¶ 61,032 at P 1 (2014).

is the appropriate long-term growth projection to be used in the two-step DCF methodology for determining the NETOs' ROE,"[187] and that "4.39[%] is the appropriate projection of long-term GDP growth" in this proceeding.[188] Based on this finding, the FERC found that, "the NETOs' existing 11.14[%] base ROE is unjust and unreasonable and that a just and reasonable base ROE is 10.57[%]."[189]

The FERC also explained how this finding impacts the NETOs' existing transmission incentive ROE adders. Specifically, the FERC stated that a "utility's total ROE, inclusive of transmission incentive ROE adders, should not exceed the top of the zone of reasonableness produced by the two-step DCF methodology."[190] Based on a 4.39% projected long-term GDP growth rate, the FERC found the appropriate zone of reasonableness for the NETOs to be 7.03% to 11.74%. Accordingly, the FERC found that the NETOs' "maximum ROE, including transmission incentive ROE adders, cannot exceed 11.74[%]."[191] The FERC ordered the NETOs to make refunds consistent with this finding.[192]

IV. MERGERS AND ACQUISITIONS

A. *Exelon Corp., 149 F.E.R.C. ¶ 61,148 (2014)*

On November 20, 2014, the FERC authorized the proposed acquisition of Pepco Holdings, Inc. (Pepco Holdings) by Exelon Corporation (Exelon, and together with Pepco Holdings, the Applicants), subject to clarification.[193]

The FERC first found that neither the proposed combination of the Applicants' generation assets nor the proposed combination of their demand response resources would adversely affect horizontal competition.[194] The FERC also rejected assertions by the PJM market monitor that the Applicants' collective capacity market-based demand response resources could impact prices in the PJM energy market.[195] Despite acknowledging that the proposed acquisition would increase Exelon's market share, the FERC believed that the recent improvements to tariff provisions governing the dispatch and pricing of PJM's capacity market-based demand response resources will encourage competition "and lead to more efficient dispatch going forward."[196] Addressing concerns regarding increased market power in the transmission development market, the FERC held that the proposed acquisition would not materially reduce the pool of competitive developers in the PJM market.[197]

187. *Id.* at P 10.
188. *Id.*
189. *Id.*
190. *Id.* at P 11.
191. 149 F.E.R.C. ¶ 61,032 at P 11.
192. *Id.* at P 12.
193. *Exelon Corp.*, 149 F.E.R.C. ¶ 61,148 at P 1 (2014).
194. *Id.* at PP 44-45.
195. *Id.* at PP 46-48.
196. *Id.* at P 48.
197. *Id.* at P 49.

The FERC further found that the proposed acquisition would not have an adverse effect on vertical competition.[198] According to the FERC, the proposed acquisition would not empower the Applicants to withhold natural gas transportation service at the detriment of rival generators.[199] The FERC explained that none of the Applicants' generation facilities would be directly connected to their limited gas distribution facilities.[200] Because the Applicants transferred operational control of their transmission facilities to PJM, the FERC held that the proposed acquisition would not enable the Applicants to favor Exelon's generation resources.[201] The FERC also rejected PJM market monitor's concerns that the Applicants could utilize the interconnection-study process to discriminate against other generators.[202]

In addition, the FERC agreed that the proposed acquisition would not have an adverse impact on rates, because the Applicants had no captive wholesale customers and they committed to holding the transmission customers harmless from the rate effects of the merger for a period of five years.[203] However, if the Applicants seek authorization to recover merger-related costs that are subject to their hold-harmless commitment, the FERC clarified that they would be required to file their proposal under section 205 of the FPA, as well as in a concurrent informational filing.[204] The FERC explained that the Applicants' filing under section 205 of the FPA would be required to specifically identify the merger-related costs they seek to recover and to demonstrate that those costs are exceeded by the savings produced by the merger and realized by jurisdictional customers.[205] The FERC further clarified that it would not authorize the recovery of merger-related costs in an annual informational filing under the Applicants' existing formula rates.[206] Rather, the FERC stated that the Applicants' proposal would be noticed and subject to public comment.[207]

The FERC finally concluded that the proposed acquisition would not create a regulatory gap at the state or federal levels,[208] or an "inappropriate cross-subsidization, . . . pledge[,] or encumbrance of utility assets for the benefit of an associate company."[209]

V. COMPLAINTS

A. *New England Power Generators Association, Inc. v. ISO New England Inc.*,

198. 149 F.E.R.C. ¶ 61,148 at P 77.
199. *Id.*
200. *Id.*
201. *Id.* at 79.
202. *Id.* at 80.
203. 149 F.E.R.C. ¶ 61,148 at P 105.
204. *Id.* (citing 16 U.S.C. § 824d (2012)).
205. *Id.* at P 107.
206. *Id.* at P 106.
207. *Id.*
208. 149 F.E.R.C. ¶ 61,148 at P 120.
209. *Id.* at 134.

146 F.E.R.C. ¶ 61,039 (2014)

On January 24, 2014, the FERC granted in part and denied in part the New England Power Generator Association's (NEPGA) complaint against ISO-NE alleging that certain provisions of ISO-NE's Transmission, Markets, and Services Tariff relevant to the FCM were unjust, unreasonable, and unduly discriminatory.[210] The FERC found that the tariff's current administrative pricing provisions for existing resources in situations of inadequate supply and insufficient competition were unjust and unreasonable because those provisions would produce prices for FCA 8 that were not reflective of supply conditions.[211]

The FERC determined that the tariff's "Inadequate Supply and Insufficient Competition provisions erroneously tie[d] administrative prices for existing resources to the most recent auction *without* Inadequate Supply or Insufficient Competition (depending on the provision at issue)."[212] Therefore, "[t]he resultant prices would generally not reflect supply conditions in an FCA where new capacity was needed . . . , and competitive prices would generally be higher to reflect the higher costs associated with new entry."[213]

Moreover, the FERC found that the potential disparity between the administratively set prices under the then-current tariff and those of a competitive auction may be exacerbated by the fact that "the New England region has had a capacity surplus since implementing the FCM, and the Capacity Clearing Prices in the first seven FCAs were set by operation of the price floor in the Tariff."[214] The FERC explained that, in every FCA up to the date the order was issued, new capacity had not been needed, with the exception of one Capacity Zone in one auction.[215] The FERC noted, however, that nearly 10% of the region's existing capacity resources had recently submitted Non-Price Retirement Requests, stating their intent to leave the market prior to FCA 8.[216] Despite the potentially significant shift in the region's capacity supply since FCA 7, the FERC determined that under the proposed Inadequate Supply and Insufficient Competition provisions, existing capacity resources would receive a price above the price paid to most existing resources in FCA 7, and was "$0.03/kW-month above the average Capacity Clearing Price of the first seven auctions."[217] According to the FERC, the higher prices showed that "tying prices under the Inadequate Supply and Insufficient Competition rules to prices in a prior auction with adequate supply and sufficient competition [would send] illogical price signals that undermine the very purpose of those rules."[218] The FERC rejected NEPGA's proposed administrative price rate of 1.1 times the "Offer Review Trigger Price" for a

210. *New England Power Generators Ass'n, Inc. v. ISO New England Inc.*, 146 F.E.R.C. ¶ 61,039 (2014).

211. *Id.* at P 47. The FERC did not adopt NEPGA's proposed solution as just and reasonable. The FERC established the relevant just and reasonable rates in a concurrently issued companion order in Docket No. ER14-463-000. *Id.* at P 1.

212. *Id.* at P 49.

213. *Id.*

214. *Id.* at P 50.

215. 146 F.E.R.C. ¶ 61,039 at P 50.

216. *Id.*

217. *Id.*

218. *Id.*

combustion turbine under conditions of Inadequate Supply and Insufficient Competition.[219]

The FERC also found that NEPGA had not shown the existing "Capacity Carry Forward Rule" to be unjust and unreasonable; accordingly, the FERC denied NEPGA's complaint on that issue.[220] The FERC stated that NEPGA mischaracterized the rule and failed to show that it would not function as intended. The FERC asserted that if capacity is carried forward from an FCA, it does not necessarily follow that the subsequent FCA into which the capacity is carried will have excess capacity.[221] Further, the FERC rejected the assertion that the rule's pricing provision "does not represent a reasonable proxy for a competitive market outcome."[222]

B. PJM Interconnection, L.L.C., 148 F.E.R.C. ¶ 61,144 (2014)

On August 29, 2014, the FERC instituted a proceeding pursuant to section 206 of the FPA to investigate whether PJM tariff applies the Financial Transmission Rights Forfeiture Rule (FTR Forfeiture Rule)[223] to up-to-congestion (UTC) transactions in a just and reasonable manner.[224]

On June 10, 2013, PJM filed revisions to its Open Access Transmission Tariff and its Amended and Restated Operating Agreement to formally define UTC transactions and clarify the rules concerning the use of such transactions.[225] PJM proposed to formally define UTC transactions as virtual transactions and to distinguish UTC transactions from the other types of virtual transactions.[226] In revising its definition of UTC transactions, PJM intended to "limit the LMP spread between a UTC transaction's source and sink points, and limit the eligible source-sink paths."[227] PJM proposed to apply the FTR Forfeiture Rule to UTC transactions and to apply its daily limit of 3,000 virtual transactions to UTC transactions.[228] The PJM filing clarified that these proposed tariff revisions are "designed to reflect the evolution of the UTC product from a financial hedge of real-time congestion charges associated with physical transactions to [that of] a purely virtual product."[229]

On August 9, 2013, the FERC accepted PJM's proposed tariff revisions on the condition that PJM submit a compliance filing setting forth an explanation of

219. *Id.* at PP 53-54.

220. 146 F.E.R.C. ¶ 61,039 at P 56.

221. *Id.* at P 57.

222. *Id.* at P 59.

223. The FTR Forfeiture Rule provides that if a company or one of its affiliate companies submits an Increment Offer (INC) or Decrement Bid (DEC) at or near the source or sink location of one of its FTRs which results in a higher LMP spread in the Day-ahead Energy Market than in the Real-time Energy Market, then the FTR profit for that particular FTR will be forfeited. *See* PJM Operating Agreement Schedule 1, section 5.2.1(b). For additional explanation of INCs and DECs, please refer to note 231, *infra*.

224. *PJM Interconnection, L.L.C.*, 148 F.E.R.C. ¶ 61,144 (2014).

225. *PJM Interconnection, L.L.C.*, 144 F.E.R.C. ¶ 61,121 at P 1 (2013).

226. *Id.*

227. *Id.* at P 6.

228. *Id.* at P 8.

229. *Id.* at P 1.

how PJM intends to apply the FTR Forfeiture Rule to UTC transactions.[230] The FERC required that the PJM explain in a compliance filing whether and how its proposed treatment of UTC transactions differs from the treatment of two other types of virtual transactions–INCs or DECs.[231] The FERC also required that, if PJM concludes that its treatment of UTCs does in fact differ from that of INCs or DECs, PJM must explain the divergent approaches to these types of virtual transactions in an informational filing.[232] PJM submitted its compliance filing on September 6, 2013.

In its August 29, 2014, order, the FERC found that PJM's compliance filing did not adequately resolve issues concerning the proposed application of the FTR Forfeiture Rule to UTCs and virtual transactions.[233] To address these concerns, the Commission instituted an investigation pursuant to section 206 of the FPA to address whether the PJM tariff applies the FTR forfeiture rule to UTCs in a just and reasonable manner and directed FERC staff to hold a technical conference to explore these issues with interested parties.[234] The Commission set the refund effective date as the date of publication in the *Federal Register*, which occurred on September 8, 2014.[235]

C. Buckeye Power, Inc. v. American Transmission Systems Inc., Opinion No. 533, 148 F.E.R.C. ¶ 61,174 (2014)

On September 8, 2014, the FERC issued an order on initial decision rejecting the use of voltage-differentiated transmission rates on transmission facilities of American Transmission Systems Incorporated (ATSI) in PJM.[236] This proceeding was initiated by a complaint, filed under sections 206 and 306 of the FPA by Buckeye Power, Inc. (Buckeye).[237]

Prior to the FERC's decision, the rates for transmission service on ATSI transmission facilities are voltage-differentiated, allowing ATSI to charge two separate rolled-in rates for use of transmission facilities operating at different voltage levels.[238] As a result, Buckeye and its members paid both the ATSI Bulk Transmission System rate for service on transmission facilities operating at 138 kV and above, and also the ATSI Area Transmission System rate for service on

230. 144 F.E.R.C. ¶ 61,121 at P 3.

231. *Id.* at 27. "An INC is an offer in the day-ahead energy market to supply virtual generation." *Id.* at P 5 n.3. "[A] DEC is a bid in the day-ahead energy market for virtual demand." *Id.* "[A]n INC/DEC can create a positive revenue stream by arbitraging the expected difference between the day-ahead and real-time LMP at a specific pricing node." *Id.*

232. *Id.*

233. 148 F.E.R.C. ¶ 61,144 at P 2.

234. *Id.*

235. *Id.* at P 15.

236. *Buckeye Power, Inc. v. Am. Transmission Sys. Inc.*, 148 F.E.R.C. ¶ 61,174 (2014). ATSI owns and operates "7,300 circuit-miles of transmission facilities that operate at 345 kV, 138 kV, and 69 kV in Ohio and western Pennsylvania," and is a transmission owner member of PJM. *Id.* at PP 2-3.

237. *Id.* at P 6. Buckeye is a generation and transmission cooperative operating in Ohio. Buckeye and its member distribution cooperatives are transmission dependent utilities. Buckeye owns no transmission facilities and is a network integrated transmission customer in the ATSI zone of PJM. *Id.* at P 3.

238. *Id.* at P 4.

the transmission facilities that operate at 69 kV.[239] On July 18, 2011, Buckeye filed a complaint alleging that ATSI's voltage-differentiated rates should be replaced with a rolled-in rate reflecting the cost of all ATSI transmission facilities, regardless of voltage.[240] On October 20, 2011, the FERC found that "there were genuine issues of material fact with respect to Buckeye's claims" and established hearing and settlement judge procedures.[241]

On January 11, 2013, the presiding Administrative Law Judge (ALJ) held a hearing and subsequently issued an Initial Decision declaring ATSI's existing voltage-differentiated transmission rate design unjust, unreasonable, and unduly discriminatory, and preferential.[242] The ALJ acknowledged that "the Commission's policy favors a roll-in of rates on integrated transmission systems," and found that the "existing ATSI voltage-differentiated rate design should be replaced with a single zonal rate design that reflects the costs of all the zonal transmission facilities, regardless of voltage."[243]

The FERC affirmed the ALJ's findings, concluding that ATSI's existing voltage-differentiated rates had become unjust, unreasonable, unduly discriminatory, or preferential, and that "a single rolled-in rate reflecting the cost of all ATSI transmission facilities, without voltage differentiation, was a just and reasonable, and not unduly discriminatory or preferential alternative rate."[244] The FERC explained that, in this case, voltage-differentiated rates are inappropriate because the 69 kV facilities are part of an integrated transmission system providing service to all of ATSI's customers.[245]

D. California Wind Energy Association v. California Independent System Operator Corp., 147 F.E.R.C. ¶ 61,050 (2014).

On April 17, 2014, the FERC denied a complaint requesting that the FERC prohibit the transfer of operational control of certain transmission assets in the Southern California Edison Company (SoCal Edison) transmission network from the CAISO to the SoCal Edison.[246]

In 2009, after identifying several reliability criteria violations on its Antelope and Bailey 66 kV system, SoCal Edison proposed the creation of the East Kern Wind Reliability Area 66 kV Reconfiguration Project (EKWRA Project) to reconfigure the Antelope and Bailey system from a looped system integrated with the CAISO grid to three separate radial systems classified as non-integrated local

239. 148 F.E.R.C. ¶ 61,174 at P 5. The Bulk Transmission System rate is charged to recover costs associated with transmission facilities operating at 138 kV or higher and is assessed to all transmission customers. *Id.* The Area Transmission System rate is assessed to recover costs associated with transmission facilities operating at 69 kV and is assessed only to transmission customers with loads connected to these facilities. *Id.*

240. *Id.* at P 6.

241. *Id.* at P 7.

242. 148 F.E.R.C. ¶ 61,174 at P 8. The ALJ concluded that ATSI's rate design does not satisfy the cost causation principle and does not allocate the costs of the ATSI transmission system in proportion to the benefits that customers receive from them. *Id.* at P 8.

243. *Id.* at PP 9-10.

244. *Id.* at P 1.

245. *Id.* at P 9.

246. *Cal. Wind Energy Ass'n v. Cal. Indep. Sys. Operator*, 147 F.E.R.C. ¶ 61,050 at P 1 (2014).

distribution facilities.[247] SoCal Edison requested that the CAISO relinquish operational control of the Antelope and Bailey facilities "in accordance with the terms of the Amended and Restated Transmission Control Agreement among CAISO and Transmission Owners (Transmission Control Agreement)."[248] On December 15, 2013, "CAISO relinquished operational control over the Antelope and Bailey 66 kV facilities" to SoCal Edison.[249]

On December 17, 2013, California Wind Energy Association (CWEA) and First Solar, Inc. (collectively, Complainants) filed a complaint under section 206 of the FPA alleging that the transfer of operational control to SoCal Edison violates CAISO's transmission control agreement, may negatively impact grid reliability, and "will have unjust and unreasonable rate consequences for generators affected by the transfer."[250]

In its April 17, 2014, order on the complaint, the FERC concluded that the Complainants had not shown the transfer of operational control over the Antelope and Bailey 66 kV facilities to be unjust, unreasonable, unduly discriminatory, or preferential.[251] The FERC applied the five-factor test established in *Mansfield Municipal Electric Department v. New England Power Co.* (*Mansfield*)[252] to determine whether control over the facilities should remain with CAISO or be relinquished to SoCal Edison.[253] The FERC concluded that: (1) the transfer of operational control satisfies the *Mansfield* test in this case; (2) CAISO provided the required notice and comment period; and (3) CAISO's evaluation of the facility reconfiguration is consistent with the requirements of the Transmission Control Agreement.[254] Further, the FERC concluded that the present facts do not indicate that relinquishment of control "will negatively impact power flows from generators connected to the Antelope and Bailey 66 kV facilities, or impair CAISO's ability to perform tariff functions intended to improve market efficiency."[255] The FERC also determined that pre-existing CAISO interconnection agreements do not prohibit SoCal Edison from making the appropriate filings before the FERC to ensure that facilities are interconnected as a result of a system reconfiguration.[256]

E. Formula Rate Protocol Proceedings: Empire District Electric Co., 148 F.E.R.C. ¶ 61,030 (2014); Louisville Gas & Electric Co., 148 F.E.R.C. ¶ 61,031 (2014); UNS Electric, Inc., 148 F.E.R.C. ¶ 61,032 (2014); Westar Energy, Inc., 148 F.E.R.C. ¶ 61,033 (2014); Kansas City Power & Light Co., 148 F.E.R.C. ¶

247. *Id.* at P 2.
248. *Id.* at P 3.
249. *Id.* at P 4.
250. *Id.* at P 1.
251. 147 F.E.R.C. ¶ 61,050 at P 34.
252. *Id.* at P 3 (citing to *Mansfield Mun. Elec. Dep't*, Opinion No. 454, 97 F.E.R.C. ¶ 61,134 (2001)).
253. *Id.* at P 21.
254. *Id.* at PP 35, 39.
255. *Id.* at P 38.
256. 147 F.E.R.C. ¶ 61,050 at P 55.

61,034 (2014); Black Hills Power, Inc., 148 F.E.R.C. ¶ 61,035 (2014)

On July 17, 2014, pursuant to FPA section 206, the FERC issued six substantively nearly-identical orders, which instituted investigations and directed the target entities to file or show cause why they should not be required to file new or revised formula rate protocols.[257] The FERC noted that in orders concerning its investigation of the formula rate protocols of MISO,[258] it found the existing MISO protocols were insufficient to ensure just and reasonable rates because of concerns about "the scope of participation, the transparency of the information exchange, and the ability of customers to challenge transmission owners' implementation of the formula rate as a result of the information exchange."[259] In each of the six orders, the FERC found the targeted entity's existing formula rate protocols were insufficient in these areas,[260] or that the entity lacked formula rate protocols,[261] so that its formula rate appeared to be unjust and unreasonable. The FERC required compliance filings within sixty days and set the date of publication of notice of the investigation in the *Federal Register* as the FPA section 206(b) refund date.[262]

F. San Diego Gas & Electric Co. v. Sellers of Energy & Ancillary Services Into Markets Operated by the California Independent System Operator Corp. & the California Power Exchange, Opinion No. 536, 149 F.E.R.C. ¶ 61,116 (2014)

On November 10, 2014, the FERC issued an order addressing certain remaining issues arising out of the 2000-2001 California energy crisis.[263] The order partially affirmed factual findings made in an initial decision[264] following an evidentiary hearing directed by the FERC in an order[265] issued in response to a remand from the United States Court of Appeals for the Ninth Circuit in *Public Utilities Commission of the State of California v. FERC*.[266] In the order issued on November 10, 2014, the FERC addressed the California market participants' liability for refunds relating to transactions entered into during the period from May 1, 2000, to October 2, 2000 (the Summer Period), and for forward

257. *Empire Dist. Elec. Co.*, 148 F.E.R.C. ¶ 61,030 at P 1 (2014) (*Empire District*); *Louisville Gas & Elec. Co.*, 148 F.E.R.C. ¶ 61,031 at P 1 (2014) (*Louisville*); *UNS Elec., Inc.*, 148 F.E.R.C. ¶ 61,032 at P 1 (2014) (*UNS*); *Westar Energy, Inc.*, 148 F.E.R.C. ¶ 61,033 at P 1 (2014) (*Westar*); *Kan. City Power & Light Co.*, 148 F.E.R.C. ¶ 61,034 at P 1 (2014) (*KC*); *Black Hills Power, Inc.*, 148 F.E.R.C. ¶ 61,035 at P 1 (2014) (*Black Hills*).

258. *Midwest Indep. Transmission Sys. Operator, Inc.*, 139 F.E.R.C. ¶ 61,127 (2012), *order on investigation*, 143 F.E.R.C. ¶ 61,149 (2013) (MISO Investigation Order), *order on reh'g*, 146 F.E.R.C. ¶ 61,209 (2014), *order on compliance*, 146 F.E.R.C. ¶ 61,212 (2014) (MISO Compliance Order).

259. *Empire District* at P 6; *Louisville* at P 7; *UNS* at P 7; *Westar* at P 6; *KC* at P 6; *Black Hills* at P 6.

260. *Empire District* at PP 10-28; *Westar* at P 15-35; *KC* at PP 13-29; *Black Hills* at PP 10-28.

261. *Louisville* at PP 10-22; *UNS* at PP 13-22.

262. *Empire District* at PP 29-30; *Louisville* at PP 23-24; *UNS* at PP 23-24; *Westar* at PP 36-37; *KC* at PP 30-31; *Black Hills* at PP 29-30.

263. *San Diego Gas & Electric Co. v. Sellers of Energy & Ancillary Servs.*, 149 F.E.R.C. ¶ 61,116 at P 1 (2014).

264. *San Diego Gas & Electric Co. v. Sellers of Energy & Ancillary Servs.*, 142 F.E.R.C. ¶ 63,011 (2013).

265. *San Diego Gas & Electric Co. v. Sellers of Energy & Ancillary Servs.*, 129 F.E.R.C. ¶ 61,147 (2009). For a full description of this decision, see *Report of the Electricity Regulation Committee*, 32 ENERGY L.J. 265, 313-14 (2010).

266. 462 F.3d 1027 (9th Cir. 2006). For a full description of this decision, see *Report of the Electricity Regulation Committee*, 28 ENERGY L.J. 269, 333-34 (2007).

transactions and energy exchanges entered into during the period from October 2, 2000, to June 20, 2001 (the Refund Period).[267] The FERC did not address the initial decision's factual findings with respect to several market participants that had entered into settlements that had been approved by the FERC.[268] In addition, the FERC dismissed from the proceeding two non-jurisdictional entities, Bonneville Power Administration and Western Area Power Administration, on the ground that the FERC had no authority to order those entities to pay refunds.[269]

With respect to the Summer Period, the FERC affirmed the initial decision's findings that certain respondents had committed various tariff and other violations that impacted the market-clearing price in the California organized electricity markets, including the markets operated by the California Power Exchange (CalPX) and the CAISO.[270] The tariff violations at issue included: Type II anomalous bids (defined as "bids above marginal cost [that] were used in conjunction with other anti-competitive tariff strategies");[271] Type III anomalous bids (defined as "bids set so high above the market price that such bids [would] likely not be accepted, thereby either reducing the available supply . . . or increasing the market clearing price");[272] False Export (defined as purchasing CalPX energy, exporting it out of the CAISO control area, and subsequently returning it "disguised as energy sourced from outside CAISO");[273] and False Load Scheduling (defined as "fraudulently creat[ing] a positive imbalance that was effectively 'sold' at the real-time *ex post* price in the CAISO real-time imbalance market").[274] In addition, the FERC found that one entity had sold ancillary services at market-based rates, without being authorized to do so by the FERC.[275] The FERC also affirmed the initial decision's findings that other alleged tariff violations had not been shown to have impacted the market-clearing price during the relevant period.[276] The FERC determined that the appropriate remedy for Type II and III anomalous bids, False Exports, and False Load Scheduling violations would be the disgorgement of payments received by the respondents in excess of the applicable marginal cost proxy price, and that the appropriate remedy for selling ancillary services at market-based rates without FERC authorization would be disgorgement of excess payments above the cost of providing such services.[277] The FERC required respondents to submit compliance filings showing their calculations of excess payments and overcharges due for disgorgement, including any proposed cost offsets.[278]

267. 149 F.E.R.C. ¶ 61,116 at P 1.

268. *Id.* at P 18.

269. *Id.* at P 22. The FERC nevertheless declined to vacate the initial decision's findings with respect to the conduct of the non-jurisdictional entities. *Id.* at P 23.

270. *Id.* at P 3.

271. *Id.* at P 51.

272. 149 F.E.R.C. ¶ 61,116 at P 51.

273. *Id.* at P 108.

274. *Id.* at P 135.

275. *Id.* at P 200.

276. *Id.* at P 193.

277. 149 F.E.R.C. ¶ 61,116 at P 209.

278. *Id.* at P 210.

With respect to the Refund Period, the FERC affirmed the initial decision's finding that a particular forward market transaction was not just and reasonable.[279] The FERC rejected arguments that the transaction at issue was subject to review under the heightened *Mobile-Sierra* standard, noting that the transaction was made subject to the terms of the CAISO tariff, and thus was subject to the "Memphis Clause" in that tariff.[280] The FERC noted that one segment of the transaction already had been subject to mitigation as a spot market transaction, and concluded that treating the two remaining segments of the transaction differently from the mitigated segment "is not justifiable."[281] Finally, the FERC concluded that the forward market transaction was similar to out-of-market spot transactions that had been engaged in by CAISO and that had been subject to mitigation.[282] The FERC further affirmed the initial decision's finding that the forward market transaction should be mitigated based upon the mitigated market clearing price that had been used for determining refunds for spot market transactions during the Refund Period.[283]

279. *Id.* at P 230.
280. *Id.*
281. *Id.* at P 233.
282. 149 F.E.R.C. ¶ 61,116 at PP 231-32, 234.
283. *Id.* at P 235.

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