

REPORT OF THE POWER GENERATION & MARKETING SUBCOMMITTEE

The following is the report of the Energy Bar Association’s Power Generation and Marketing Subcommittee. In this report, the Committee summarizes key developments in state and federal regulation of power generation and marketing from July 2015 to June 2016.*

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I. HUGHES V. TALEN ENERGY MARKETING, LLC

In April, the Supreme Court in a unanimous decision, ruled that a Maryland regulatory program that guaranteed a rate for an electric generator’s sales into a wholesale market impermissibly intruded on the FERC’s exclusive jurisdiction over wholesale energy markets.¹ The Supreme Court reaffirmed the judgment of the U.S. Court of Appeals for the Fourth Circuit (Fourth Circuit),² which had affirmed the District Court’s finding that the Maryland subsidy program improperly set the rate a generator receives for interstate wholesale capacity sales to PJM Interconnection, L.L.C. (PJM), clearly infringing on the FERC’s exclusive authority over interstate wholesale rates.³

The Maryland Public Service Commission (MDPSC), concerned that prices in the PJM capacity auction were insufficient to attract development of new in-state generation, solicited proposals in 2009 to construct a new gas-fired power plant at a particular location in the Maryland PJM market area and ultimately accepted a proposal by CPV Maryland, LLC (CPV).⁴ Subsequently, the MDPSC

* Special thanks to contributions from Michael Blackwell, Glenn E. Camus, Emanuel T. Cocian, Water R. Hall, II, and Patrick L. Morand.

1. Hughes v. Talen Energy Marketing, LLC, 136 S. Ct. 1288 (2016).

2. PPL EnergyPlus, LLC v. Nazarian, 753 F.3d 467 (4th Cir. 2014).

3. PPL EnergyPlus, LLC v. Nazarian, 974 F. Supp. 2d 790, 840 (D. Md. 2013).

4. *Id.* at 820, 822.

required all load serving entities (LSEs) to enter into a twenty-year contract for differences with CPV at a rate that CPV had specified in its accepted proposal.⁵ This design would allow CPV to sell its capacity in the PJM market and, as long as its capacity cleared the market, receive the contract price rather than the auction clearing price if the clearing price was below the price guaranteed in the contract for differences.⁶ The Supreme Court, in its ruling, agreed with the Fourth Circuit in concluding that the Maryland program was functionally setting an interstate wholesale rate with the rate that CPV receives for its sales in the PJM auction, clearly infringing upon the authority of the FERC established by the Federal Power Act, but clarified that its holding is limited to the Maryland program only and did not address the permissibility of other state programs that encourage the development of new or clean generation.⁷

II. ORDERS REVISING PJM MARKET STRUCTURE

The Commission issued major orders over the past year both approving PJM proposed energy and capacity market structures and directing modifications in such PJM market structures. In *PJM Interconnection, L.L.C.*, the Commission denied rehearing and generally approved PJM's compliance filings respecting two major tariff modifications affecting the Reliability Pricing Model (RPM - PJM's capacity market).⁸ In its May 2016 order, the Commission rejected challenges posed by state public service commissions, public power and end-user representatives to the necessity, cost-benefit, and structuring of PJM's Capacity Performance Program (CP Program).⁹ The CP Program establishes new, substantially increased performance standards for generation to participate in PJM's capacity market (such requirements to be phased in over a four-year period), proposes substantial penalty and reward payments for failure to supply electricity during system stress periods (also phased in over a four-year period), alters market mitigation rules to permit recovery of the costs to achieve this enhanced performance, and modifies certain other rules perceived as permitting inadequate generator performance.¹⁰

In rejecting challenges to the necessity of the CP Program,¹¹ the Commission accepted PJM evidence that RPM "failed to fully ensure that capacity resources will perform when called upon," and has thus, "threatened reliability, while requiring consumers to pay for capacity that might lack a sufficient . . . reliability

5. Order No. 84815, In re *Whether New Generating Facilities Are Needed to Meet Long-Term Demand for Standard Offer Service*, No. 9214 (Public Serv. Comm'n Md. Apr. 12, 2012).

6. *Id.* at 4.

7. *Hughes*, 136 S. Ct. at 1299.

8. *PJM Interconnection, L.L.C.*, 155 F.E.R.C. ¶ 61,157 (May 10, 2016). Not all matters decided by the Commission in its 137- page order are summarized in these paragraphs. The Order affirmed upon rehearing was *PJM Interconnection, L.L.C.*, 151 F.E.R.C. ¶ 61,208 (June 9, 2015).

9. *Id.*

10. *Id.* at P 4-9. See also *PJM Interconnection, L.L.C.*, 151 F.E.R.C. ¶ 61,208 (June 9, 2015).

11. Opponents of the CP Program argued that other actions taken by PJM, to establish winterization programs and to monitor generator readiness to operate during peak load seasons were sufficient to correct this performance degradation. However, the Commission, by implication, concluded that both were needed. 155 F.E.R.C. ¶ 61,157 at P 25 (2016).

benefit.”¹² It noted that, PJM evidence established that “generator equivalent forced outage rates have steadily increased,” reaching 22% in January, 2014, and “have worsened over the last ten years . . . from approximately 6% to 10%.”¹³ It also rejected arguments that it should perform a formal cost-benefit evaluation of the CP Program, stating that no such requirement was imposed upon its decision-making and that it was free to consider non-cost factors which would not contribute to such an analysis, but gave material support to its approval of the PJM program.¹⁴ It stated:

We conclude that, based on the record in this proceeding, the reliability benefits of PJM’s proposal are significant. Customers will receive greater assurance that the resources needed to keep their lights on will deliver when needed because the Capacity Performance reforms will incentivize better performance and penalize poor performance, thereby allowing PJM to meet its reliability objective at a reasonable cost over time.¹⁵

State public service commissions, load interests, and generators requested a rehearing challenging PJM’s proposed structure of the reward/penalty payment. PJM proposed that the numerator of the equation to produce the penalty payment should equal Net CONE (i.e., the cost deemed necessary per megawatt (MW) to incentivize new generation construction), not the RPM clearing price actually paid to generators (which normally has been significantly less).¹⁶ Generators argued that this would result in rewards/penalties in excess of RPM revenues and would, thus, be unfair.¹⁷ State public service commissions and load interests argued that the denominator of the equation, the number of Performance Assessment Hours (representing system stress hours during which penalties or rewards are incurred, estimated by PJM as thirty), was too large (as compared to average historic values over the last three years) and would result in rewards and penalties that are too small to achieve the desired incentive effect.¹⁸ However, by combining these two values, the Commission both accepted PJM reasoning and data indicating that each was appropriate and fell within historic norms and that combined they would achieve a just and reasonable result.¹⁹

Several additional matters with significant market impact were also addressed. For example, PJM proposed that generation unable to perform as Capac-

12. *Id.* at P 4.

13. *Id.* at PP 23-25.

14. *Id.* at PP 30-34.

15. *Id.* at P 31.

16. 155 F.E.R.C. ¶ 61,157, at PP 62-64.

17. *Id.* at P 64.

18. *Id.* at P 62-63.

19. *Id.* at PP 65-73 The Commission also rejected arguments that reward/penalty stop-loss limits (i.e., maximum limits on penalties assessed) were too low and that expanded exemptions from such penalty payments based on PJM-accepted operational parameter limits should be allowed. *Id.* at PP 74-112. The Commission denied a second request by PJM to establish exemptions from the penalty payment obligation where a generator fails to perform due to following PJM dispatch instructions or to operating consistent with a ramp rate previously approved by PJM. The Commission explained that the importance of maintaining maximum reach for the incentive structure and its function of improving reliability exceeded the need demonstrated for the exemptions. Order Rejecting Tariff Amendments, *PJM Interconnection, L.L.C.*, 155 F.E.R.C. ¶ 61,213 (May 31, 2016).

ity Performance (CP) resources should be permitted to form an “aggregated resource” and jointly offer as a CP resource.²⁰ Storage, Intermittent, and Demand Resources (DR) are the resources understood as most likely to require use of this vehicle to participate in RPM once the requirement that all resources have CP capability becomes effective (i.e., in 2020). Existing PJM DR products, such as Limited and Extended Summer DR, are eliminated.²¹ State public service commissions sought rehearing on these matters, but the FERC rejected the request, concluding that “PJM has provided reasonable accommodation to permit greater participation in the capacity market by such resource types, including a reasonable transition period and the ability to participate in aggregated offers.”²²

Also, the Commission established a new default offer cap which substantially alters and limits the application of PJM’s market power limitation rules.²³ The new default offer cap equals Net CONE multiplied by the Balancing Ratio.²⁴ Seller Market Offers into RPM at a cost below this level are not to be mitigated despite the recognized presence of market power throughout PJM’s capacity market.²⁵ Market mitigation was previously applied wherever a Seller’s Market Offer exceeded its marginal cost of capacity, typically a much lower value. Rejecting state public service commission and public power opposition,²⁶ the Commission affirmed its earlier finding that the higher default offer cap was needed to permit generators to make the investments needed to satisfy the performance requirements of the CP Program and to recover a generator’s “opportunity costs” of accepting CP status.²⁷

Chairman Bay dissented from the order, stating the basis of his dissent as follows:

20. 155 F.E.R.C. ¶ 61,157, at P 47-53.

21. *Id.* at PP 54-60, 113-26. PJM’s proposed methods for measuring DR capacity levels delivered, opposed by DR Providers, were also affirmed by the Commission.

22. *Id.* at P 59. The circumstances under which DR (or other non-CP performance compliant capacity, such as intermittent resources, storage, etc.) will participate in the RPM following full implementation of the CP Program in 2020 is presently unclear. In its report analyzing the 2015 base residual auction, the IMM highlights the cost significance of this uncertainty, noting that loss of this capacity would result (all else equal) in a \$1.7 billion (15.6%) increase in RPM costs imposed upon load; MONITORING ANALYTICS, ANALYSIS OF THE 2018/2019 RPM BASE RESIDUAL AUCTION REVISED 8 (July 5, 2016), http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_2018_2019_RPM_BaseResBaseR_Auction_20160630.pdf (hereafter 2018/2019 Analysis). However, PJM and its stakeholders are actively addressing this uncertainty and expect to adopt new rules for such inclusion by the end of 2016. See Seasonal Capacity Resources Seasonal Task Force Meeting Notes, <http://www.pjm.com/committees-and-groups/task-forces/scrstf.aspx>.

23. 155 F.E.R.C. ¶ 61,157 at PP 174-178, 182-186.

24. *Id.* at P 174.

25. MONITORING ANALYTICS, 2015 STATE OF THE MARKETS REPORT FOR PJM, SECTION 5 - CAPACITY MARKET (March 2016); 2018/2019 ANALYSIS, *supra* note 22; 155 F.E.R.C. ¶ 61,157, at page 5.

26. 155 F.E.R.C. ¶ 61,157, at P 182-186. State public service commissions argued, unsuccessfully, that if the CP Program was to be successful, as PJM and the Commission assert that it will be, extensive opportunity costs, stated to be the loss of Performance Bonus Payments by generators who accept CP status, will not exist, as few penalties will be collected (the sole fund from which Bonus Payments are made) and, thus, Bonus Payments will be small. 155 F.E.R.C. ¶ 61,157, at P 178.

27. *Id.* In its only grant of rehearing of the order, the Commission rejected its previously accepted force majeure modification applicable to PJM’s allocation of ARR and FTRs to load serving entities, noting that this provision applied to PJM’s own responsibilities and not those of Capacity Performance generators. 155 F.E.R.C. at PP 253, 260.

I dissented [from the June 2015 order] on two basic grounds. First, the Commission failed to adequately consider the costs of the proposed changes or to compare those costs with the potential benefits. Indeed, the record to date suggests that the multi-billion dollar cost to consumers exceeds the benefits. Furthermore, and equally important, the market design itself is flawed. Compensation for capacity resources is so generous, and the penalties for non-performance are so weak, that resources can profit even if they are unable to perform when they are most needed, thereby undercutting the very purpose of the program. . . . I must respectfully dissent.²⁸

The Chairman noted that PJM estimated the incremental cost of its CP Program at \$2.5 to \$4.2 billion, and that alternative programs, as argued in rehearing petitions, had substantially reduced the reliability concerns advanced in support of the program's approval.²⁹ The Chairman explained the market design flaw as the combination of the default offer cap described above which, he explained, permitted the improper exercise of market power and the further fact that the thirty-hour performance assessment estimate well exceeded the historic occurrence of such hours, resulting in a penalty structure whose performance incentive was inadequate to achieve the program's objectives.³⁰

Finally, the order, in addition to resolving issues on rehearing, also addressed a number of disputes over whether PJM's compliance filing fully implemented the Commission's decisions, finding that in a number of cases proposed tariff language was not fully adequate, requiring a further compliance filing.³¹ Review of these matters continued through mid-summer 2016. Petitions for Review of the June 9, 2015, and May 10, 2016, orders have been filed by public power entities, DR providers, and certain environmental groups, and are pending as of November, 2016.

In an October 15, 2015, Order on Rehearing and Compliance, the Commission affirmed in its entirety a November 28, 2014 order which rejected challenges to PJM's RPM modifications made following PJM's Third Triennial Review of its capacity markets' operation.³² PJM had proposed, and the Commission approved, three modifications to its Variable Resource Requirement Curve (i.e., VRR demand curve), as well as to inputs used in that curve including cost of new entry (CONE) and methods for the determination of energy and ancillary service revenue offsets.³³ State public service commissions, public power, and other load interests challenged on rehearing three modifications proposed by PJM and approved by the Commission to the operation of the VRR curve, contending that the cost of these modifications to load far exceeded any reliability or other benefit received.³⁴ The Commission, however, concluded that reliability improvements

28. *Id.* at Chairman Bay Dissent at p. 1.

29. *Id.* at Chairman Bay Dissent at pages 2-4.

30. *Id.* at Chairman Bay Dissent at pages 4-9.

31. 155 F.E.R.C. ¶ 61,157, at PP 283-356.

32. Order Conditionally Accepting Tariff Revisions Subject to Compliance Filing, *PJM Interconnection, L.L.C.*, 149 F.E.R.C. ¶ 61,183 (2014); Order on Rehearing and Compliance, *PJM Interconnection, L.L.C.*, 153 F.E.R.C. ¶ 61,035 (2015).

33. 153 F.E.R.C. ¶ 61,035, at PP 2, 8; *see generally* 149 F.E.R.C. ¶ 61,183.

34. 153 F.E.R.C. ¶ 61,035, at P 8-34. These parties argued, unsuccessfully, that additional costs imposed by the VRR curve modifications would approximate between \$1 and \$1.7 billion per year based upon simulations of the curve modification effects in recent RPM base residual auctions. The Commission, however, concluded

obtaining a 6% improvement in one loss of load metric, given ongoing changes in PJM capacity levels and characteristics, rendered the changes in the public interest in light of the Commission's much lower estimate of the costs imposed on load by these modifications.³⁵ The Commission also rejected challenges by generators to PJM's proposed Net CONE values, based on allegations of higher capital and other generation development costs than those recognized by PJM.³⁶ Petitions for review have been filed by generators seeking appellate review of the latter two issues described above and are pending as of November, 2016.

Several more limited orders have also altered PJM markets during the past year. The most significant is *PJM Interconnection, L.L.C.*, in which the Commission stated the principles upon which it would approve hourly market offers in the PJM energy market.³⁷ State public service commissions, the PJM Market Monitor (IMM), and load representatives opposed PJM's proposal, asserting that it would permit generators to exercise both "aggregate" market power and in certain instances, the exercise of local market power.³⁸ To prevent such improper exercise, the IMM proposed that hourly market offers only be allowed where necessary to permit recovery of variable fuel costs or where the supply offer mark-up percentage (i.e., profit) remains constant.³⁹ While concluding that the IMM's concerns with "aggregate" or local market power had not been established, and that consideration of the latter was beyond the scope of the proceeding, the Commission urged PJM and the IMM to investigate those concerns more fully in stakeholder proceedings.⁴⁰ Nonetheless, it rejected the IMM's proposed limitations on PJM hourly bidding, but also rejected PJM's proposal as lacking in sufficient detail as to how market power mitigation of generator hourly market bids would be affected.⁴¹ It directed PJM to file a revised proposal consistent with the guidance provided in its order within thirty days.⁴²

In *PJM Interconnection, L.L.C.*, the Commission largely affirmed the method used by the PJM IMM to calculate the market power mitigation offer where a generator is found to have market power in the PJM capacity market (RPM).⁴³ The IMM had historically used the lower of a generator's cost-based or market-based bid to determine its fuel cost offset, which offset reduces the net market revenue offset to the Avoidable Cost Rate, thus increasing the market power offer

that this additional cost imposition would equal but \$214 million. Nonetheless, in its July 5, 2016 report analyzing the results of the 2015 RPM base residual auction, the first to apply the modified VRR curve, the IMM quantified the cost increase imposed on load by the changed VRR curve shape as equaling \$893million (an 8.2% increase). These parties also challenged the meaningfulness and methods used in PJM's monte carlo simulation upon which the purported reliability improvements were demonstrated. 2018/2019 Analysis MONITORING ANALYTICS, *supra* note 22, at 7.

35. *Id.* at 24-34.

36. 153 F.E.R.C. ¶ 61,035 at PP 57-84.

37. Order on Proposed Tariff Provisions, *PJM Interconnection, L.L.C.*, 155 F.E.R.C. ¶ 61,282 (2016).

38. *Id.* at P 37.

39. *Id.* at PP 37-39.

40. *Id.*

41. *Id.* at PP 45-46, 53-54.

42. Order on Proposed Tariff Revisions, *PJM Interconnection, L.L.C.*, 155 F.E.R.C. ¶ 61,282 at P 100 (2016).

43. Order on Section 206 Investigation, *PJM Interconnection, L.L.C.*, 154 F.E.R.C. ¶ 61,151 (2016); *reh'g denied* 155 F.E.R.C. ¶ 61,281 (2016).

cap applied to a seller.⁴⁴ Generators argued, and PJM supported, that the cost-based offer provided a more accurate figure, as that bid was developed to comply with PJM's cost determination manual. The Commission, however, agreed with the IMM that "in most circumstances an accepted non-zero energy offer that is less than a resource's cost-based offer is an appropriate measure of short-run marginal cost and when available, should be used in the calculation of a Market Seller Offer Cap for capacity."⁴⁵ In response to the generator argument, however, the Commission adopted two exceptions to this rule applicable (1) when the resource is mitigated and the market-based offer exceeds the cost-based offer cap, and (2) when the generator can demonstrate that its fuel and environmental costs exceed its market based offer.⁴⁶ In *PJM Interconnection, L.L.C.*, the Commission approved a PJM proposal to modify and standardize the method used to calculate Lost Opportunity Cost payments in offer caps employed in its energy market.⁴⁷

III. ORDERS INCREASING OFFER CAPS IN RTO/ISO ENERGY MARKETS

As one element of the regional transmission organization (RTO)/independent system operator (ISO) Energy Market Rules—which prevents the exercise of market power that improperly increases energy market prices imposed upon end-users—the Commission has imposed a \$1,000 offer cap on market seller offer bids into such markets.⁴⁸ This offer cap is in addition to market power mitigation activities of RTO/ISO Market Monitors whereby market seller offers where market power is present are limited to an IMM-determined or accepted marginal electricity production cost.⁴⁹ In recent years, during extreme weather events, certain RTOs/ISOs have requested temporary waivers of these caps to prevent generator non-recovery of electricity production costs caused by extreme spikes in natural gas prices.⁵⁰

In *PJM Interconnection, L.L.C.*, PJM requested a permanent increase in this cap.⁵¹ The Commission approved its request, increasing the cap from \$1,000 to \$2,000 megawatt hour (MWH) and further permitting offers above this level where supported by generator cost data, but such offers are not permitted to establish the market clearing price.⁵² Rather, only the affected generator who demonstrates to the IMM and PJM that these high costs have in fact been experienced receives payment at the level above \$2,000 proved to have occurred.⁵³ Other gen-

44. 154 F.E.R.C. ¶ 61,151, at P 4.

45. 154 F.E.R.C. ¶ 61,151 at P 53.

46. *Id.* at P 59.

47. 152 F.E.R.C. ¶ 61,165 (2015).

48. Order Granting Waiver, *PJM Interconnection, L.L.C.*, 146 F.E.R.C. ¶ 61,078 at PP 1-6 (2014).

49. *Id.*

50. See Order Accepting Proposed Tariff Revisions and Ordering Further Filings, *PJM Interconnection, L.L.C.*, 150 F.E.R.C. ¶ 61,020 (2015); Order Granting Waiver, *PJM Interconnection, L.L.C.*, 146 F.E.R.C. ¶ 61,041; *reh'g denied* 149 F.E.R.C. ¶ 61,059 (2014); Order Granting Waiver, *PJM Interconnection, L.L.C.*, 146 F.E.R.C. ¶ 61,078 (2014); Order Granting Waiver, *N.Y. Indep. Sys. Operator, Inc.*, 146 F.E.R.C. ¶ 61,061 (2014).

51. Order Accepting Proposed Tariff and Operating Agreement Revisions, *PJM Interconnection, L.L.C.*, 153 F.E.R.C. ¶ 61,289 (2015).

52. *Id.* at P 10.

53. *Id.* at P 4.

erators not experiencing these high costs will be permitted to receive only the market clearing price which cannot exceed \$2,000/MWH.⁵⁴ In addition, a 10% “uncertainty” factor permitted to be added to demonstrated cost levels is not permitted to apply to justify offers with a price above \$2,000/MWH.⁵⁵

In January, the Commission issued a Notice of Proposed Rulemaking in which it proposed

[T]o require that each [RTO/ISO] cap each resource’s incremental energy offer to the higher of \$1,000/MWH or that resource’s verified cost-based incremental energy offer. . . . Under the proposal, verified cost-based incremental energy offers above \$1,000/MWH would be used for purposes of calculating Locational Marginal Prices (LMPs).⁵⁶

The Commission explained:

The Commission finds that the offer cap on incremental energy offers (offer cap) may no longer be just and reasonable for several reasons. The offer cap may unjustly prevent a resource from recouping its costs by not permitting that resource to include all of its short-run marginal costs within its energy supply offer (supply offer). The offer cap may result in unjust and unreasonable rates because it can suppress LMPs to a level below the marginal cost of production. Further, because of the offer cap, a resource with short-run marginal costs above that cap may choose not to offer its supply to the RTO/ISO, even though the market may be willing to purchase that supply. Finally, when several resources have short-run marginal costs above the offer cap but are unable to reflect those costs within their incremental energy offers due to the offer cap, the RTO/ISO is not able to dispatch the most efficient set of resources because it will not have access to the underlying costs associated with the multiple incremental energy offers above the offer cap.⁵⁷

Only verified cost-based incremental energy offers above \$1,000/MWH would be used for purposes of calculating Locational Marginal Prices.⁵⁸ Verification is to be performed by the RTO/ISO Market Monitor using procedures and data similar to that used in market power mitigation activities. The Commission explained that rulemaking is necessary to implement these changes and to prevent market seam issues arising if different offer caps are adopted in different regional markets.⁵⁹ Comments are requested on a number of aspects of the proposal, including (1) whether a hard cap above which offers would not be permitted even if cost justified should be imposed, (2) how a pre-auction verification process could be developed and operate, and (3) whether imports and virtual transactions could be permitted to set LMPs in conjunction with the new offer caps.⁶⁰

IV. STATE PROGRAMS TO DETER RETIREMENT OF NUCLEAR AND COAL

54. *Id.* at PP 11-13, 25-32.

55. *Id.* at P 4.

56. Notice of Proposed Rulemaking, *Offer Caps in Markets Operated by Regional Transmission Operators and Independent System Operators*, 154 F.E.R.C. ¶ 61,038 at P 1 (2016).

57. *Id.* at P 2.

58. *Id.*

59. *Id.* at PP 3-4.

60. *Id.* at PP 73, 83-86.

GENERATION

The further decline of natural gas prices in the last several years has resulted in an inability of certain nuclear and coal generation to recover their costs of operation from RTO/ISO markets. Owners of this generation have sought the adoption of state programs to enhance their revenues from RTO/ISO markets to achieve full cost recovery and, thereby, avoid the necessity to retire such plants. Major developments in these efforts occurred over the past year which, if ultimately successful, will benefit plants in New York, Ohio, and Illinois.

In July, the New York Public Service Commission (NYPSC) released for public comment a “Clean Energy Standard Proposal” developed by its staff to value zero-emission attributes of upstate New York nuclear plants (i.e., Fitzpatrick, Ginna and Nine Mile Point).⁶¹ The proposal is based on a Commission-approved method for establishing the societal value of carbon. Staff estimates that by investing \$965 million in payments to assure generator cost-recovery and, thus, avoid retirement of such plants, over the first two years of the program electric end-users and the state will achieve \$5 billion in benefits.⁶² Those benefits derive from maintenance of 27.6 million MWH annually of zero-emission electric generation, thereby reducing carbon emissions into the atmosphere by 31 million metric tons having a societal value of \$1.4 billion.⁶³ Additional direct economic benefits of \$1.7 billion result from preservation of 2,600 well-paying jobs, property tax payments, and maintenance of fuel diversity in the electric system.⁶⁴ Valuation of carbon emission reduction uses a U.S. Interagency Working Group- developed societal cost of carbon.⁶⁵

Payments will be made under the program when the NYPSC has made a determination of “public necessity” that such payments are needed to preserve their zero-emission environmental attributes. Payments are to reflect the difference between facility operating cost and compensation received from all NYISO markets and will be established by the NYPSC. “Public necessity” determinations will be made for two-year periods, with the expectation that the program will continue through March 31, 2029. Payments will be made in return for “Zero-Emission Contracts” provided by the generator to the New York State Research and Development Authority.⁶⁶

In March, the Ohio Public Utilities Commission (PUCO) issued two decisions approving separate programs proposed by American Electric Power Company (AEP) and FirstEnergy Corp. to obtain revenues needed to cover the cost of

61. See Press Release, N.Y. Pub. Serv. Comm’n, PSC Seeks Public comment on Clean Energy Standard Proposal, <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={F593762A-253D-48F7-95F4-3E5D54B16982}> (last visited Oct. 19, 2016); *Matter Master*, N.Y. STATE DEP’T PUB. SERV., <http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterSeq=48235&MNO=15-E0302> (last visited Oct. 19, 2016) (at line item 51).

62. Press Release, *supra* note 61.

63. See Staff’s Responsive Proposal for Preserving Zero-Emissions Attributes (filed July 8, 2016) in State of New York Public Service Commission Case No. 15-E-0302, Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard.

64. *Id.*

65. *Id.*

66. *Id.* at pages 3-5.

operating certain Ohio nuclear and coal plants and thereby prevent their retirement.⁶⁷ The Commission concluded that the programs would achieve financial benefits for Ohio retail consumers, serve as financial hedges to stabilize Ohio retail rates, promote retail competition, and promote renewable energy development and other desirable matters.⁶⁸

Complaints were filed at FERC by a number of generators against the two Ohio programs. These complaints seek rescission of Commission orders waiving the Commission's affiliate power sales restrictions as to AEP and First Energy and the proposed Affiliate PPAs, which would have the effect of requiring that the PPAs be filed with the Commission for approval.⁶⁹ Complainants argue that the PPAs return Ohio retail customers to captive status, subsidize plants with above market cost and will adversely affect competition in PJM markets.⁷⁰ In April, because of the changed circumstances effected by the proposed programs, the FERC granted the requested relief in response to each complaint and rescinded its previously granted waiver.⁷¹ A further complaint related to these matters was filed by a number of generators on April 11, 2016, against PJM seeking modifications to its Minimum Offer Price Rule to counter the asserted adverse effects on market pricing of the PUCO-approved PPAs.⁷²

In June, Exelon announced plans to shut down its Clinton and Quad Cities nuclear generation units in Illinois after failing to obtain legislation to establish a Clean Energy Standard that would provide state-supported revenues for the plants.⁷³ It noted the plants had failed to recover their costs in the amount of \$800 million over the past seven years despite good operational performance.⁷⁴ Exelon will continue to seek passage of the legislation but such passage is not expected in time to defer retirement of the plants on June 1, 2017 and 2018, respectively.

V. FERC ORDER SUMMARY: REACTIVE POWER REQUIREMENTS FOR NON-

67. Application of Ohio Edison Company, Case No. 14-1297-EL-SSO, 2016 Ohio PUC Lexis 270 (March 31, 2016)(hereafter Ohio Edison); Application of Ohio Power Co., Case No. 14-1693-EL-RDR No.14-1694-EL-AAM, 2016 Ohio PUC Lexis 269 (March 31, 2016)(Ohio Power).

68. *Ohio Edison*, *supra* note 67 at 20-21, 182-185, 239-240, 260-266, 289-295; Ohio Power, *supra* note 67 at 9-11, 51-53, 187-212, 266-267. Applications for rehearing filed by a number of parties were granted in each case. See *In re the Application Seeking Approval of Ohio Power Company's Proposal to Enter into an Affiliate Power Purchase Agreement for Inclusion in the Power Purchase Agreement Rider*, No. 14-1693-EL-RDR, 2016 Ohio PUC LEXIS 512 (May 25, 2016); *In re Application of Ohio Edison Co.*, 2016 Ohio PUC LEXIS 446 (May 11, 2016).

69. See Complaint Requesting Fast Track Processing, *Elec. Power Supply Ass'n v. AEP Generation Res., Inc.*, Docket No. EL16-33-000 (Apr. 27, 2016); Complaint Requesting Fast Track Processing, *Elec Power Supply Assn. v. FirstEnergy Solutions Corp.*, Docket No. EL16-34-000 (April 27, 2016).

70. *Id.*

71. *Elec. Power Supply Ass'n v. AEP Generation Res. Inc.*, 155 F.E.R.C. ¶ 61,102 (2016); *Elec. Power Supply Ass'n v. First Energy Solutions Corp.*, 155 F.E.R.C. ¶ 61,101 (2016).

72. *Calpine Corporation v. PJM Interconnection, L.L.C.*, No. EL16-49-000 (Apr. 11, 2016).

73. *Exelon Announces Early Retirement of Clinton and Quad Cities Nuclear Plants*, EXELON CORP. (June 2, 2016), <http://www.exeloncorp.com/newsroom/clinton-and-quad-cities-retirement> [hereinafter EXELON CORP.].

74. *Id.*

SYNCHRONOUS GENERATION

In June, the FERC issued Order No. 827, Reactive Power Requirements for Non-Synchronous Generation, to eliminate reactive power exemptions for wind generators and to establish reactive power requirements for non-synchronous generation.⁷⁵ Order No. 827 revises the pro forma Large Generator Interconnection Agreement (LGIA), Appendix G of the LGIA, and the pro forma Small Generator Interconnection Agreement (SGIA).⁷⁶ In addition, the order requires newly interconnecting non-synchronous generators that have not yet executed a Facilities Study Agreement to provide dynamic reactive power within the range of 0.95 leading to 0.95 lagging at the high-side of the generator substation.⁷⁷ In recent years, the cost of equipment needed for a wind generator to provide reactive power has decreased significantly.⁷⁸ In recognition of this development, in May 2015, the Commission accepted a proposal by PJM to remove wind generator exemptions from the PJM tariff.⁷⁹ In November 2015, the Commission issued a Proposal to Revise Standard Generator Interconnection Agreements that proposed eliminating the exemptions for wind generators from the requirement to provide reactive power as contained in the LGIA, Appendix G to the LGIA, and the SGIA.⁸⁰ In June, the Commission issued Order No. 827 to eliminate exemptions for wind generators from the requirement to provide reactive power and establish reactive power requirements for non-synchronous generation.⁸¹

Order No. 827 requires all public utility transmission providers to adopt the requirements of Order No. 827 as revisions to the LGIA and SGIA in their Open Access Transmission Tariffs (OATTs) within ninety days after publication of the final rule in the Federal Register.⁸² Transmission providers that are not public utilities also must adopt the requirements of the final rule as a condition of maintaining the status of their safe harbor tariff or otherwise satisfying the reciprocity requirement of Order No. 888.⁸³ Order No. 827 requires “all newly interconnecting non-synchronous generators to design their Generating Facilities to meet the

75. Final Rule, *Reactive Power Requirements for Non-Synchronous Generation*, 155 F.E.R.C. ¶ 61,277 at P 1 (2016).

76. *Id.*

77. *Id.*

78. See generally, e.g., FED. ENERGY REG. COMM’N, PAYMENT FOR REACTIVE POWER 4-5 app. 2, (2014).

79. Order Conditionally Accepting Tariff Revisions and Directing Compliance Filing, *PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,097 at P 6 (2015).

80. Notice of Proposed Rulemaking, *Reactive Power Requirements for Non-Synchronous Generation*, 80 Fed. Reg. 73,683, 18 C.F.R. pt 35 (2015).

81. Order No. 827, *Reactive Power Requirements for Non-Synchronous Generation*, 155 F.E.R.C. ¶ 61,277 at P 1 (2016) [hereinafter Order No. 827].

82. *Id.* at P 2.

83. Order No. 888, *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Cost by Public Utilities and Transmitting Utilities*, 75 F.E.R.C. ¶ 61, 080 at P 61,085 (1996).

reactive power requirements at all levels of real power output, as is already required of synchronous generators.”⁸⁴ Order No. 827 does not change the “Commission’s existing policies on compensation for reactive power.”⁸⁵ The Commission will apply the requirements of Order No. 827 to all “newly interconnecting non-synchronous generators that have not yet executed a Facilities Study Agreement.”⁸⁶ The Commission “will not apply the requirements of this final rule to existing non-synchronous generators making upgrades to their Generating Facilities that require new interconnection requests.”⁸⁷ “However, such a generator may be required to provide reactive power if a transmission provider determines through that generator’s System Impact Study that a reactive power requirement is necessary to ensure safety or reliability.”⁸⁸

VI. CFTC PROPOSES TO ALLOW PRIVATE PARTIES TO SUE PARTICIPANTS IN CERTAIN RTOS AND ISOS FOR FRAUD AND MANIPULATION

In May, the Commodity Futures Trading Commission (CFTC) proposed an amendment to an order issued on March 28, 2013, exempting specified transactions of particular ISOs and RTOs from certain provisions of the Commodity Exchange Act (CEA) and CFTC regulations.⁸⁹ In the March 28, 2013 order (RTO-ISO Order), the CFTC excepted from the exemption the CFTC’s general anti-fraud and anti-manipulation authority, scienter-based prohibitions under CEA section 22, and any implementing regulations promulgated under the CEA including CFTC regulations.⁹⁰

On February 3, 2015, the U.S. District Court for the Southern District of Texas dismissed a private lawsuit for market manipulation on the ground that section 22 of the CEA was not available to the plaintiffs under the RTO-ISO Order.⁹¹ The U.S. Court of Appeals for the Fifth Circuit affirmed the District Court’s ruling in February 2016.⁹² Prior to the Fifth Circuit ruling, the CFTC issued a proposed order on May 18, 2015 in response to Southwest Power Pool, Inc.’s (SPP) request for an exemption substantially similar to that provided in the RTO-ISO Order.⁹³ As proposed, the SPP proposed order did not exempt SPP from the private right of action under CEA section 22 and the CFTC further stated in the order that in its

84. Order No. 827, *supra* note 81, at P 47.

85. *Id.* at P 52.

86. *Id.* at P 22.

87. *Id.* at P 59.

88. *Id.*

89. Notice of Proposed Order, *Amendment to and Request for Comment on the Final Order in Response to a Petition From Certain Independent System Operators and Regional Transmission Organizations to Exempt Specified Transactions Authorized by a Tariff or Protocol*, 81 Fed. Reg. 30,245 (2016).

90. Final Order, *Response to a Petition From Certain Independent System Operators and Regional Transmission Organizations to Exempt Specified Transactions Authorized by a Tariff or Protocol Approved by the Federal Energy Regulatory Commission or the Public Utility Commission*, 78 Fed. Reg. 19,880 (2013).

91. *Aspire Commodities, L.P. v. GDF Suez Energy N. Am., Inc.*, 2015 WL 500482, Util. L. Rep. 14919 (S.D. Tex. 2015).

92. *Aspire Commodities, L.P. v. GDF Suez Energy N. Am., Inc.*, 2016 WL 758689, Comm. Fut. L. Rep. 33,649 (5th Cir. 2016).

93. Notice of Proposed Order, *Application for an Exemptive Order from Southwest Power Pool, Inc. from Certain Provisions of the Commodity Exchange Act*, 80 Fed. Reg. 29,490 (2015).

view the RTO-ISO Order does not prevent private claims for fraud or manipulation under the CEA.⁹⁴ The comment period for the Notice of Proposed Order ended June 15, 2016.

VII. FERC V. ELECTRIC POWER SUPPLY ASSOCIATION

In January, the Supreme Court reversed the decision of the U.S. Court of Appeals for the District of Columbia Circuit (Court of Appeals) and reaffirmed that the FERC acted within its authority under the Federal Power Act when it issued Order No. 745, setting standards for demand response measures and pricing in wholesale markets.⁹⁵

The FERC issued Order No. 745 in 2011 requiring that demand response providers in wholesale markets be compensated at the same rate as electricity generators.⁹⁶ The rule includes a net benefits test to ensure that the demand response resource is a cost-effective alternative to generation resources for balancing supply and demand.⁹⁷ The Supreme Court in reversing the decision of the Court of Appeals concluded that the FERC was within its authority under the Federal Power Act to regulate the demand response prices and the compensation formula used was not arbitrary and capricious.⁹⁸

VIII. FERC ORDER NO. 816, REFINEMENTS TO POLICIES AND PROCEDURES FOR MARKET-BASED RATES FOR WHOLESALE SALES OF ELECTRIC ENERGY, CAPACITY AND ANCILLARY SERVICES BY PUBLIC UTILITIES

In October, the FERC issued Order No. 816, a final rule amending its regulations that govern market-based rate authorizations “for wholesale sales of electric energy, capacity, and ancillary services by public utilities.”⁹⁹ The FERC described Order No. 816 as “another step” in its “efforts to modify, clarify and streamline certain aspects of its market-based rate program” including eliminating or refining certain filing requirements, while requiring submission of additional information from market-based rate sellers.¹⁰⁰ The FERC’s analysis for granting market-based rate authority includes determining “whether the seller and its affiliates lack, or have adequately mitigated, market power in generation” (i.e., horizontal market power) and in transmission (i.e., vertical market power), “whether the seller and its affiliates have the ability to erect other barriers to entry,” and “whether there is evidence involving the seller or its affiliates relating to affiliate abuse or reciprocal dealing.”¹⁰¹

94. *Id.* at 29,493.

95. FERC v. Elec. Power Supply Ass’n, 136 S. Ct. 760, 763 (2016).

96. Order No. 745, *Final Rulemaking, Demand Response Compensation in Organized Wholesale Energy Markets*, F.E.R.C. STATS. & REGS. ¶ 31,322, 76 Fed. Reg. 16,658 (2011) (to be codified at 18 C.F.R. pt. 35).

97. *Id.* at 16,659.

98. *Elec. Power Supply Corp.*, 136 S. Ct. at 773.

99. Order No. 816, *Refinements to Policies and Procedures for Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, 153 F.E.R.C. ¶ 61,065 at P 3 (2015) [hereinafter Order No. 816].

100. *Id.* at P 2.

101. *Id.* at P 4.

Historically, the FERC utilizes two indicative screens, the pivotal supplier screen and the wholesale market share screen which assess whether sellers may have horizontal market power.¹⁰² Passing “both indicative screens establishes a rebuttable presumption that the seller does not possess horizontal market power.”¹⁰³ If a seller fails either indicative screen, the seller may present evidence to demonstrate that it does not have market power.¹⁰⁴ Vertical market power analyses address, where a seller or any of its affiliates owns, operates, or controls transmission facilities, whether the seller has a FERC-approved OATT on file (or has received waiver of the OATT requirement), and considers the seller’s ability to erect other barriers to entry such as having ownership of or control over inputs to electric power production.¹⁰⁵

With respect to its horizontal market power analysis, the FERC declined in Order No. 816 to adopt a proposal that would relieve market-based rate sellers in RTO/ISO markets of the obligation to submit indicative screens, clarifying that, where a seller fails the indicative screens for an RTO/ISO market, the seller would continue to be able to obtain or retain market-based rate authority by relying on FERC-approved RTO/ISO monitoring and mitigation.¹⁰⁶ The FERC also clarified in Order No. 816 that, “when all of a seller’s generation capacity is sold on a long-term firm basis to one or more buyers, the seller has no uncommitted capacity and in such cases will not be required to file the indicative screens.”¹⁰⁷ The FERC explained that, “to qualify as fully committed, a seller must commit the capacity to a non-affiliated buyer so that none of it is available to the seller or its affiliates for one year or longer.”¹⁰⁸

The FERC explained that “horizontal market power analysis centers on and examines the balancing authority area where the seller’s generation is physically located” and further explained that “the default relevant geographic market under both indicative screens will be first, the balancing authority area where the seller is physically located . . . and second, the markets directly interconnected to the seller’s balancing authority area (first-tier balancing authority area markets).”¹⁰⁹ In Order No. 816, the FERC adopted a proposal to define the default relevant geographic markets for an independent power producer (IPP) located in a generation-only balancing authority area as “the balancing authority areas of each transmission provider to which the IPP’s generation-only balancing authority area is directly interconnected” and further defined an eligible IPP as “a generation resource that has power production as its primary purpose, does not have any native load obligation, is not affiliated with any transmission owner located in the target or first-tier markets in which the IPP is competing and does not have an affiliate with a franchised service territory.”¹¹⁰ The FERC required such an IPP “to study

102. *Id.* at P 5.

103. *Id.*

104. Order No. 816, *supra* note 99, at P 5.

105. *Id.* at P 6.

106. *Id.* at PP 27-28.

107. *Id.* at P 39.

108. *Id.* at P 39.

109. Order No. 816, *supra* note 99, at P 45 (internal quotations and citations omitted).

110. *Id.* at P 61.

all of its uncommitted generation capacity from the generation-only balancing authority area in the balancing authority area(s) of each transmission provider to which it is directly interconnected.”¹¹¹ The FERC provided examples of such study scenarios, including interconnection to a trading hub.¹¹²

In addition, the FERC adopted certain other proposals regarding indicative screens including: amending indicative screen reporting formats,¹¹³ clarifying the term “import capacity,”¹¹⁴ identifying solar as an energy-limited generation resource and clarifying the capacity factors to be used for solar photovoltaic resources versus solar thermal resources,¹¹⁵ reporting of long-term firm purchases,¹¹⁶ and clarifying certain aspects of performing simultaneous transmission import limit (SIL) studies.¹¹⁷

Regarding its vertical market power analysis, the FERC adopted in Order No. 816, a proposal to eliminate the land acquisition reporting requirements.¹¹⁸ As part of their vertical market power analysis, market-based rate sellers had been required to provide a description of their ownership or control of sites for generation capacity development and to file notices of change in status on a quarterly basis when they acquired sites for new generation capacity development.¹¹⁹ The FERC explained that it found the land acquisition reporting to be of limited value in assessing barriers to entry because, while “the reports identif[ied] relevant geographic market/balancing authority areas,” they did not “indicate specific locations or whether the sites are adjacent to the existing transmission grid or natural gas pipelines.”¹²⁰ The FERC also explained that “the land acquisition reporting requirements are burdensome for sellers and yield little, if any, offsetting benefit” and that “[n]o one has used the information in a land acquisition report in a comment or protest challenging the market-based rate authority of any seller.”¹²¹

The FERC also adopted several proposals revising the requirement to file notices of change in status. Specifically, the FERC will apply a 100 MW threshold to a seller’s and/or its affiliates’ net generation capacity additions in each individual market before triggering the need to file a notice of change in status.¹²² The FERC clarified that it “will exclude markets and balancing authority areas that are first-tier to the seller’s study area” such that, “a seller need not consider its and its affiliates new generation, including generation from long-term purchase agreements, in first-tier areas in determining whether it has reached the 100 MW threshold.”¹²³ The FERC also clarified that “the 100 MW threshold applies to each new

111. *Id.* at P 62.

112. *Id.* at PP 62-64.

113. *Id.* at PP 72-83.

114. Order No. 816, *supra* note 99, at PP 84-86.

115. *Id.* at PP 87-107.

116. *Id.* at PP 108-45.

117. *Id.* at PP 146-98.

118. *Id.* at P 207.

119. Order No. 816, *supra* note 99, at P 200.

120. *Id.* at P 208.

121. *Id.* at P 209.

122. *Id.* at PP 228-30.

123. *Id.* at P 230.

relevant market (not previously studied) in which a seller and/or its affiliates acquire a cumulative net increase of 100 MW.”¹²⁴ Similarly, the FERC will apply the 100 MW threshold to a market-based rate seller that has a new affiliation with an entity with generation assets that result in a cumulative net increase of 100 MW of capacity in a relevant geographic market.¹²⁵ The FERC clarified that it will not count behind-the-meter generation in the 100 MW change in status threshold.¹²⁶

In addition, the FERC adopted revisions to the asset appendix required to be filed with a market-based rate application, market power analysis, and notice of change of status, including: revisions to and clarifications of certain column headings, reporting of long-term firm purchases of capacity and/or energy, reporting of orders accepting sellers’ OATTs, and requiring the use of an electronic spreadsheet format.¹²⁷ The FERC also clarified the distinctions between Category 1 and Category 2 sellers,¹²⁸ adopted a requirement that sellers include an organizational chart with a market-based rate application, market power analysis, or notice of change of status,¹²⁹ which provided the option to file a single corporate tariff among affiliated sellers,¹³⁰ and clarified the limitations on waivers of Parts 101 and 141 of the FERC’s regulations as applied to market-based rate sellers that are hydropower licensees.¹³¹

Order No. 816 became effective on January 28, 2016. On May 19, 2016, the FERC issued Order No. 816-A, in which it affirmed its determinations in Order No. 816 and provided clarifications with respect to certain issues.¹³²

IX. FERC ORDER NO. 819, THIRD-PARTY PROVISION OF PRIMARY FREQUENCY RESPONSE SERVICE

In November, the FERC issued Order No. 819, a final rule amending its regulations to permit the sale of primary frequency response service at market-based rates by sellers with market-based rate authority for sales of energy and capacity.¹³³ The FERC defined primary frequency response service as “a resource standing by to provide autonomous, pre-programmed changes in output to rapidly arrest large changes in frequency until dispatched resources can take over.”¹³⁴ The FERC explained that it is not “plac[ing] any limits on the types of transactions available to procure primary frequency response service,” but that Order No. 819 instead “focuses solely on how jurisdictional entities can qualify for market-based

124. Order No. 816, *supra* note 99, at P 231.

125. *Id.* at P 251.

126. *Id.* at P 252.

127. *Id.* at P 259-307.

128. *Id.* at PP 314-22.

129. Order No. 816, *supra* note 99, at PP 323-35.

130. *Id.* at PP 336-38.

131. *Id.* at PP 339-50.

132. Order No. 816-A, *Refinements to Policies and Procedures for Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, 155 F.E.R.C. ¶ 61,188 at P 3 (2016).

133. Order No. 819, *Third-Party Provision of Primary Frequency Response Service*, 155 F.E.R.C. ¶ 61,220 at P 1 (2015) [hereinafter Order No. 819].

134. *Id.* at P 1.

rates for primary frequency response service in the context of voluntary bilateral sales.”¹³⁵

The FERC in Order No. 819 determined that it would “apply the existing market power screens used for energy and capacity sales, without modification as to geographic market, to sales of primary frequency response service.”¹³⁶ The FERC clarified that transmission reservation and scheduling will not create a barrier to sales of frequency response within an interconnection because, even though transmission capacity may need to be reserved to support a sale of primary frequency response service in some cases, “in the vast majority of cases the sale of primary frequency response service should not require any transmission reservation or scheduling because, by definition, individual frequency responses would not be sustained for long enough periods to trigger a need for transmission service or schedule changes.”¹³⁷ In other words, “individual primary frequency responses [would] be short, lasting only until dispatched resources can take over” and, “after the initial autonomous response, any continuing response would be deemed to occur as a result of dispatch instructions from the relevant balancing authority, which would most likely constitute either use of regulation or operating reserves.”¹³⁸

The FERC clarified a number of issues regarding the sale of primary frequency response service at market-based rates. Specifically, the FERC clarified that it is not requiring any entity to purchase primary frequency response from third parties or to develop an organized market for primary frequency response;¹³⁹ it is not limiting the options that buyers have in procuring regulation service or primary frequency response service even though it is requiring a separate listing of ancillary services in market-based rate tariffs;¹⁴⁰ it is not requiring specific methods of information sharing, measurement, and verification;¹⁴¹ and that its definition of primary frequency response service is sufficient and requires no further differentiation based on response time or magnitude.¹⁴² The FERC also distinguished its market power analysis for primary frequency response service from that for operating reserves,¹⁴³ distinguished sellers with market-based rate authority using resources that can inject electric energy onto the interstate transmission grid from third-party sellers using demand response resources to participate in RTO/ISO markets.¹⁴⁴ It clarified that Order No. 819 applies to jurisdictional market-based rate sellers of primary frequency response service regardless of the specific equipment they may use to make the sales, and clarified that, as with most products in voluntary bilateral markets, Order No. 819 does not apply to the potential buyers of primary frequency response service.¹⁴⁵

135. *Id.* at P 13.

136. *Id.* at P 23.

137. *Id.* at P 32.

138. Order No. 819, *supra* note 133, at PP 32-33.

139. *Id.* at PP 36-37.

140. *Id.* at PP 38-41.

141. *Id.* at PP 42-45.

142. *Id.* at PP 46-51.

143. Order No. 819, *supra* note 133, at PP 52-57.

144. *Id.* at PP 58-59.

145. *Id.* at PP 60-62.

The FERC found that “a seller that already has market-based rate authority as of the effective date of [Order No. 819] is authorized as of that date to make sales of primary frequency response service at market-based rates” and required such a seller “to revise the third-party provider ancillary services provision of its market-based rate tariff to reflect that it wishes to make sales of primary frequency response service at market-based rates” the next time they make a market-based rate filing with the FERC.¹⁴⁶ Sellers of primary frequency response service will also be required to report these sales in their Electric Quarterly Reports.¹⁴⁷ Order No. 819 became effective on February 25, 2016.

146. *Id.* at P 71.

147. *Id.* at P 72.

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