DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 35

[Docket Nos. RM07–19–000 and AD07–7–000]

Wholesale Competition in Regions With Organized Electric Markets

Issued October 17, 2008.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final Rule.

SUMMARY: In this Final Rule, the Federal Energy Regulatory Commission (Commission) is amending its regulations under the Federal Power Act to improve the operation of organized wholesale electric markets in the areas of: Demand response and market pricing during periods of operating reserve shortage; long-term power contracting; market-monitoring policies; and the responsiveness of regional transmission organizations (RTOs) and independent system operators (ISOs) to their customers and other stakeholders, and ultimately to the consumers who benefit from and pay for electricity services. Each RTO and ISO will be required to make certain filings that propose amendments to its tariff to comply with the requirements in each area, or that demonstrate that its existing tariff and market design already satisfy the requirements.

DATES: *Effective Date:* This Final Rule will become effective December 29, 2008.

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I. Introduction

1. This Final Rule addresses reforms to improve the operation of organized wholesale electric power markets.[1] Improving the competitiveness of organized wholesale markets is integral to the Commission fulfilling its statutory mandate to ensure supplies of electric energy at just, reasonable and not unduly discriminatory or preferential rates. Effective wholesale competition protects consumers by providing more supply options, encouraging new entry and innovation, spurring deployment of new technologies, promoting demand response and energy efficiency, improving operating performance, exerting downward pressure on costs, and shifting risk away from consumers. National policy has been, and continues to be, to foster competition in wholesale electric power markets. This policy was embraced in the Energy Policy Act of 2005 (EPAct 2005),[2] and is reflected in Commission policy and practice. The Commission balances the mix of regulation and competition based on changing circumstances, taking into account such factors as the opportunities for competition to control market power, advances in technology, changes in economies of scale, and new state and federal laws that affect the energy industry.

2. The Commission has a duty to improve the operation of wholesale power markets. To that end, in this Final Rule, the Commission is making reforms to improve the operation of organized wholesale electric markets in the areas of demand response, long-term power contracting, market monitoring policies, and RTO and ISO responsiveness. By making these reforms, the Commission is not seeking to fundamentally redesign organized markets; rather, these reforms are intended to be incremental improvements to the operation of organized markets without undoing or upsetting the significant efforts that have already been made in providing demonstrable benefits to wholesale customers.

3. In the areas of demand response and the use of market prices to elicit demand response, the Commission is requiring RTOs and ISOs to: (1) Accept bids from demand response resources in RTOs' and ISOs' markets for certain ancillary services on a basis comparable to other resources; (2) eliminate, during a system emergency, a charge to a buyer that takes less electric energy in the real-time market than it purchased in the day-ahead market; (3) in certain circumstances, permit an aggregator of retail customers (ARC)[3] to bid demand response on behalf of retail customers directly into the organized energy market; (4) modify their market rules, as necessary, to allow the market-clearing price, during periods of operating reserve shortage, to reach a level that rebalances supply and demand so as to maintain reliability while providing sufficient provisions for mitigating market power; and (5) study whether further reforms are necessary to

[1] Organized market regions are areas of the country in which a regional transmission organization (RTO) or independent system operator (ISO) operates day-ahead and/or real-time energy markets. The following RTOs and ISOs have organized markets: PJMInterconnection, LLC (PJM), New York Independent System Operator, Inc. (NYISO), Midwest Independent Transmission System Operator, Inc. (Midwest ISO), ISO New England, Inc. (ISO New England), California Independent Service Operator Corp. (CAISO), and Southwest Power Pool, Inc. (SPP).

[2] Pub. L. 109–58, 119 Stat. 594 (2005).

[3] We will use the phrase ''aggregator of retail customers,'' or ARC, to refer to an entity that aggregates demand response bids (which are mostly from retail loads).

eliminate barriers to demand response in organized markets.

4. With regard to long-term power contracting, the Commission is requiring RTOs and ISOs to dedicate a portion of their Web sites for market participants to post offers to buy or sell power on a long-term basis. This requirement will promote greater use of long-term contracts by improving transparency among market participants.

5. To improve market monitoring, the Commission is requiring that RTOs and ISOs provide their Market Monitoring Units (MMU) with access to market data, resources and personnel sufficient to carry out their duties, and that the MMU (or the external MMU in a hybrid structure) report directly to the RTO or ISO board of directors.[4] In addition, the Commission is requiring that the MMU's functions include: (1) Identifying ineffective market rules and recommending proposed rules and tariff changes; (2) reviewing and reporting on the performance of the wholesale markets to the RTO or ISO, the Commission, and other interested entities; and (3) notifying appropriate Commission staff of instances in which a market participant's behavior may require investigation. The Commission is also expanding the list of recipients of MMU recommendations regarding rule and tariff changes, and broadening the scope of behavior to be reported to the Commission.

6. The Commission is also modifying MMU participation in tariff administration and market mitigation, requiring each RTO and ISO to include ethics standards for MMU employees in its tariff, and requiring each RTO and ISO to consolidate all its MMU provisions in one section of its tariff. The Commission is expanding the dissemination of MMU market information to a broader constituency, with reports made on a more frequent basis than they are now, and reducing the time period before energy market bid and offer data are released to the public.

7. Finally, the Commission establishes an obligation for each RTO and ISO to make reforms, as necessary, to increase its responsiveness to customers and other stakeholders and will assess each RTO's or ISO's compliance using four responsiveness criteria: (1) Inclusiveness; (2) fairness in balancing diverse interests; (3) representation of minority positions; and (4) ongoing responsiveness.

[4] Our use of the phrase ''board of directors'' also includes the board of managers, board of governors, and similar entities.

8. In each of these four areas, the Commission is requiring each RTO or ISO to consult with its stakeholders and make a compliance filing that explains how its existing practices comply with the Final Rule in this proceeding, or its plans to attain compliance.

9. Significant differences exist between regions, including differences in industry structure, mix of ownership, sources of electric generation, population densities, and weather patterns. Some regions have organized spot markets administered by an RTO or ISO, and others rely solely on bilateral contracting between wholesale sellers and buyers. We recognize and respect these differences across various regions. At the same time, wholesale competition can serve customers well in all regions. The focus of this Final Rule is to further improve the operation of wholesale competitive markets in organized market regions.

II. Background

10. The Commission has acted over the last few decades to implement Congressional policy to expand the wholesale electric power markets to facilitate entry of new generators and to support competitive markets. Absent a single national power market, the development of regional markets is the best method of facilitating competition within the power industry, and the Commission has made sustained efforts to recognize and foster such markets.

11. In 2007, the Commission held several public conferences to gather information and address issues on competition at the wholesale level and other related issues.[5] At these conferences, the Commission examined issues affecting competition in the RTO and ISO regions, including the levels of wholesale prices, the need for long-term power contracts, the effectiveness of market monitoring, and the lack of adequate demand response. The Commission also addressed concerns related to the RTO and ISO board of directors' responsiveness to their customers and other stakeholders.

12. On June 22, 2007, the Commission issued an Advance Notice of Proposed Rulemaking (ANOPR),[6] identifying four specific issues in organized market regions that were not being adequately addressed or were not under consideration in other proceedings. These areas were: (1) The role of demand response in organized markets and greater use of market prices to elicit demand response during periods of operating reserve shortage; (2) increasing opportunities for long-term power contracting; (3) strengthening market monitoring; and (4) enhancing the responsiveness of RTOs and ISOs to customers and other stakeholders, and ultimately to the consumers who benefit from and pay for electricity services. The Commission presented preliminary views on proposed reforms for these areas and sought comment on them.

[5] Three technical conferences were held on February 27, 2007, April 5, 2007, and May 8, 2007.

[6] *Wholesale Competition in Regions with Organized Electric Markets,* Advance Notice of Proposed Rulemaking, FERC Stats. & Regs. ¶ 32,617 (2007).

13. After receiving and considering over a hundred comments on the ANOPR, on February 22, 2008, the Commission issued a Notice of Proposed Rulemaking (NOPR).[7] In the NOPR, pursuant to the Commission's responsibility under sections 205 and 206 of the Federal Power Act (FPA),[8] the Commission proposed reforms in the four specific areas identified above that were designed to ensure just and reasonable rates, to remedy undue discrimination and preference, and to improve wholesale competition in regions with organized markets. As noted in the NOPR, these proposed reforms are intended to improve the operation of wholesale competition in organized markets.[9]

14. In the NOPR, the Commission also noted that the reforms proposed in this proceeding do not represent its final effort to improve the functioning of competitive organized markets for the benefit of consumers; rather, the Commission will continue to evaluate specific proposals that may strengthen organized markets.[10] To that end, for example, the Commission proposed to require each RTO or ISO to study whether further reforms are necessary to eliminate barriers to demand response in organized markets. Any reforms must ensure that demand response resources are treated on a basis comparable to other resources. The Commission also ordered two staff technical conferences: (1) One to investigate proposals by American Forest and the Portland Cement Association, *et al.* to modify the design of organized markets;[11] and (2) a separate conference to consider several issues related to demand response participation in wholesale

[7] *Wholesale Competition in Regions with Organized Electric Markets,* Notice of Proposed Rulemaking, 73 FR 12,576 (March 7, 2008), FERC Stats. & Regs. ¶ 32,628 (2008).

[8] 16 U.S.C. 824d—824e.

[9] NOPR, FERC Stats. & Regs. ¶ 32,628 at P 11.

[10] *Id.* P 1.

[11] The technical conference was held on May 7, 2008. *See* Supplemental Notice of Technical Conference, Capacity Markets in Regions with Organized Electric Markets, Docket No. AD08–4–000 (April 25, 2008).

markets.[12] Further, the Commission directed each RTO or ISO to provide a forum for affected consumers to voice specific concerns (and to propose regional solutions) on how to improve the efficient operation of competitive markets.[13]

III. Discussion

A. Demand Response and Pricing During Periods of Operating Reserve Shortages in Organized Markets

15. This section of the Final Rule makes several reforms to further eliminate barriers to demand response participation in organized energy markets. These reforms are to ensure that demand response is treated comparably to other resources. To that end, the Commission will require RTOs and ISOs to: (1) Accept bids from demand response resources in their markets for certain ancillary services, on a basis comparable to other resources; (2) eliminate, during a system emergency, certain charges to buyers in the energy market for voluntarily reducing demand; (3) permit ARCs to bid demand response on behalf of retail customers directly into the RTO's or ISO's organized markets; and (4) modify their rules governing price formation during periods of operating reserve shortage to allow the market-clearing price during periods of operating reserve shortage to more accurately reflect the true value of energy.

1. Background

16. Commission policy does not favor granting preference for demand response; rather, our goal is to eliminate barriers to the participation of demand response in the organized power markets by ensuring comparable treatment of resources. This policy reflects the Commission's view that the cost of producing electricity and the value to customers of electric power varies over time and from place to place.[14] Demand response can provide competitive pressure to reduce wholesale power prices; increases awareness of energy usage; provides for more efficient operation of markets; mitigates market power; enhances reliability; and in combination with certain new technologies, can support the use of renewable energy resources, distributed generation, and advanced metering. Thus, enabling demand-side resources, as well as supply-side resources, improves the economic operation of electric power markets by aligning prices more closely with the value customers place on electric power. A well-functioning competitive wholesale electric energy market should reflect current supply and demand conditions.

17. The Commission's policy also reflects its responsibility under sections 205 and 206 of the FPA to remedy any undue discrimination and preference in organized markets. To that end, the Commission explicitly addressed demand response in its Open Access Transmission Tariff (OATT) Reform (Order No. 890) [15] and reliability standards (Order No. 693).[16]

18. Additionally, on numerous occasions, the Commission has expressed the view that the wholesale electric power market works best when demand can respond to the wholesale price.[17] Also, the Commission has issued numerous orders over the last several years on various aspects of electric demand response in organized markets, with the goal of removing unnecessary obstacles to demand response participating in the wholesale power markets of RTOs and ISOs.[18] To that end, some of these orders approved various types of demand response programs, including programs to allow demand response to be used as a capacity resource [19] and as a resource during system emergencies,[20] to allow wholesale buyers and qualifying large retail buyers to bid demand response directly into the day-ahead and real-time energy markets and certain ancillary service markets, particularly as a provider of operating reserves, as well as programs to accept bids from ARCs.[21] The Commission also has approved special demand response applications such as use of demand response for synchronized reserves and regulation service.[22] The theme underlying the Commission's approval of these programs has been to allow demand response resources to participate in these markets on a basis that is comparable to other resources.

19. While the Commission and the various RTOs and ISOs have done much to eliminate barriers to demand response in organized power markets, more needs to be done to ensure comparable treatment of all resources. Therefore, as discussed below, the Commission is taking action in this Final Rule to further eliminate barriers to demand response in organized power markets.

2. Ancillary Services Provided by Demand Response Resources

20. The Commission included several components in the NOPR obligating RTOs and ISOs to accept bids from demand response resources for ancillary services. First, demand response resources were required to meet necessary technical requirements established by the RTO or ISO in order to participate in these markets. Second, the Commission proposed that demand response resources be allowed to specify the frequency and duration of their service through the use of additional bidding parameters. Finally, the Commission proposed that RTOs and ISOs perform a small demand response resource assessment to evaluate the technical feasibility and value to the market of such smaller resources. Comments in response to these issues are addressed below.

[12] The technical conference was held on May 21, 2008. *See* Supplemental Notice of Technical Conference, Demand Response in Organized Electric Markets, Docket No. AD08–8–000 (May 13, 2008).

[13] NOPR, FERC Stats. & Regs. ¶ 32,628 at P 11.

[14] That is, for two customers at the same time and place, one customer may prefer to reduce consumption if the price is high, and the other may be willing to pay a high price to avoid curtailment in an emergency.

[15] *Preventing Undue Discrimination and Preference in Transmission Service,* Order No. 890, FERC Stats. & Regs. ¶ 31,241 (2007), *order on reh'g,* Order No. 890–A, 73 FR 2,984 (Jan. 16, 2008), FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g,* Order No. 890–B, 73 FR 39,092 (July 8, 2008), 123 FERC ¶ 61,299 (2008).

[16] *See Mandatory Reliability Standards for the Bulk-Power System,* Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g,* Order No. 693–A, 120 FERC ¶ 61,053 (2007).

[17] *See, e.g., New England Power Pool and ISO New England, Inc.,* 101 FERC ¶ 61,344, at P 44–49 (2002), *order on reh'g,* 103 FERC ¶ 61,304, *order on reh'g,* 105 FERC ¶ 61,211 (2003); *PJM Interconnection, LLC,* 95 FERC ¶ 61,306 (2001); *PJM Interconnection, LLC,* 99 FERC ¶ 61,227 (2002); *Southwest Power Pool, Inc.,* 116 FERC ¶ 61,289 (2006).

[18] *See, e.g., New York Indep. Sys. Operator, Inc.,* 92 FERC ¶ 61,073, *order on clarification,* 92 FERC ¶ 61,181 (2000), *order on reh'g,* 97 FERC ¶ 61,154 (2001); *New England Power Pool and ISO New England, Inc.,* 100 FERC ¶ 61,287, *order on reh'g,* 101 FERC ¶ 61,344 (2002), *order on reh'g,* 103 FERC ¶ 61,304, *order on reh'g,* 105 FERC ¶ 61,211 (2003); *PJM Interconnection, LLC,* 95 FERC ¶ 61,306 (2001); *PJM Interconnection, LLC,* 99 FERC ¶ 61,139 (2002); *PJM Interconnection, LLC,* 99 FERC ¶ 61,227 (2002).

[19] *See, e.g., PJM Interconnection, LLC,* 117 FERC ¶ 61,331 (2006); *Devon Power LLC,* 115 FERC ¶ 61,340, *order on reh'g,* 117 FERC ¶ 61,133 (2006), *appeal pending sub nom. Maine Pub. Utils. Comm'n v. FERC,* No. 06–1403 (DC Cir. 2007).

[20] *See, e.g., New York Indep. Sys. Operator, Inc.,* 95 FERC ¶ 61,136 (2001); *NSTAR Services Co. v. New England Power Pool,* 95 FERC ¶ 61,250 (2001); *New England Power Pool and ISO New England, Inc.,* 100 FERC ¶ 61,287, *order on reh'g,* 101 FERC ¶ 61,344 (2002), *order on reh'g,* 103 FERC ¶ 61,304, *order on reh'g,* 105 FERC ¶ 61,211 (2003); *PJM Interconnection, LLC,* 99 FERC ¶ 61,139 (2002).

[21] *See, e.g., New York Indep. Sys. Operator, Inc.,* 95 FERC ¶ 61,223 (2001); *New England Power Pool and ISO New England, Inc.,* 100 FERC ¶ 61,287, *order on reh'g,* 101 FERC ¶ 61,344 (2002), *order on reh'g,* 103 FERC ¶ 61,304, *order on reh'g,* 105 FERC ¶ 61,211 (2003); *PJM Interconnection, LLC,* 99 FERC ¶ 61,227 (2002).

[22] *See, e.g., PJM Interconnection, LLC,* 114 FERC ¶ 61,201 (2006).

a. Ancillary Services Market

21. In the NOPR, the Commission proposed to obligate each RTO or ISO to accept bids from demand response resources, on a basis comparable to any other resources, for ancillary services that are acquired in a competitive bidding process, if the demand response resources: (1) are technically capable of providing the ancillary service and meet the necessary technical requirements; and (2) submit a bid under the generally-applicable bidding rules at or below the market-clearing price, unless the laws or regulations of the relevant electric retail regulatory authority do not permit a retail customer to participate.[23] The Commission stated that this proposal would apply to competitively-bid markets, if any, for energy imbalance, spinning reserves, supplemental reserves, reactive supply and voltage control, and regulation and frequency response as defined in the *pro forma* OATT, or to the markets for their functional equivalents in an RTO or ISO tariff.[24]

22. The Commission proposed that, on compliance, an RTO or ISO must either propose amendments to its tariff to comply with the proposed requirement or demonstrate that its existing tariff and market design already satisfy the requirement. This filing would be submitted within six months of the date the Final Rule is published in the **Federal Register**. The Commission proposed to assess whether each filing satisfies the proposed requirement and issue additional orders as necessary.[25]

i. Comments

23. Many commenters support the Commission's proposal and agree that allowing demand response resources to participate in ancillary services markets would increase competition, enhance system reliability, and lower the overall price for ancillary services.[26] For instance, Public Interest Organizations assert that the presence of demand response in these markets will mitigate the exercise of market power and allow large amounts of variable resources (*e.g.*, wind and solar) to be integrated into the grid.[27] DRAM states that allowing demand response to participate in ancillary services markets and other types of wholesale markets would lead to a more viable and sustainable demand response industry, and to the availability of a larger overall demand response resource.[28] Comverge maintains that the Commission's proposal is particularly appropriate because it enables market participants to simultaneously participate in capacity markets (or resource adequacy) and operating reserve markets.[29] DRAM and APPA, while in support of the Commission's proposal, state that demand response resources must be able to meet the appropriate technical requirements.[30]

24. Several commenters state that they support the Commission's clarification in the NOPR that the proposal would not require the adoption of competitive bidding processes in areas where they were not previously used.[31] APPA states that it opposes the development of new RTO or ISO markets for ancillary services just so demand response resources could participate in them.[32] Similarly, EEI asserts that this proposal should be limited to competitively-bid markets only, as defined in the proposal.[33] Comverge also agrees with the Commission's proposed requirement that this provision apply only to competitively-bid markets, but asks the Commission to include two other services within its proposal: Out-of-Market[34] and Scarcity Pricing.[35]

25. Xcel requests that the Commission clarify that the proposed rule does not require a demand response provider to offer its potential demand response into the market.[36] Xcel argues that a demand response provider should be free to evaluate its willingness to bid its offering into the market.

26. In its reply comments, Allied Public Interests Groups note that providing for comparable treatment of demand-side resources in wholesale markets is critical to making those markets competitive, efficient, reliable and sustainable. Therefore, they ask the Commission to clarify the meaning and implication of the term ''comparable treatment.''[37]

27. NARUC argues that the state-law exemption within the NOPR should be modified to avoid displacing state authority and state policy decisions on demand response.[38] NARUC explains that this exemption places the burden on state regulators to show that the demand response proposal conflicts with state laws or regulations. NARUC would like to see this reversed, and the burden placed on the RTO or ISO to obtain the state regulator's permission to allow the demand response proposal. Similarly, Pennsylvania PUC states that the state exemption highlights a jurisdictional issue and recommends that the Commission continue to work with state authorities to eliminate these types of barriers to demand response.[39]

28. Some commenters recommend that each RTO and ISO should determine new rules for ancillary services.[40] Dominion states that each RTO and ISO should have flexibility to develop the necessary rules to modify existing ancillary services markets within its stakeholder processes.[41] Comverge suggests that these rules be determined by each RTO and ISO, but initially framed in a Commission technical conference, consistent with the Commission's substantive recommendations to amend RTO and ISO bidding rules.[42] SoCal Edison-SDG&E argue that an overly prescriptive national approach may be counterproductive.[43]

29. While Midwest Energy supports the proposal, it is concerned that the quest for comparability may evolve into a program that treats demand response preferentially with respect to competitive resource providers. It states

[23] NOPR, FERC Stats. & Regs. ¶ 32,628 at P 56.

[24] *Id.*

[25] *Id.* P 63.

[26] *E.g.*, American Forest at 5; BlueStar Energy at 1–2; California PUC at 9; Cogeneration Parties at 2–3; Dominion at 4; Duke Energy at 3; Integrys Energy at 9; ISO/RTO Council at 3–4; Industrial Coalitions at 9; Midwest Energy at 2–3; North Carolina Electric Membership at 3–4; NYISO at 5; Public Interest Organizations at 5–6; Reliant at 3; and Wal-Mart at 5.

[27] Public Interest Organizations at 4–5.

[28] DRAM at 5–6.

[29] Comverge at 11.

[30] DRAM at 4–5; APPA at 31–32.

[31] NOPR, FERC Stats. & Regs. ¶ 32,628 at P 58.

[32] APPA at 34–35.

[33] EEI at 11.

[34] It is not entirely clear what service Comverge is referring to here. It is possible that Comverge is referring to Out-Of-Market Dispatch, *i.e.*, RTO or ISO dispatch actions that are not reflected in the ISO's real-time market prices. In CAISO, for example, dispatchers procure energy to make up for imbalances by contacting selected resources or control area operators that chose not to submit any bids into the ISO's or RTO's markets. This practice results in bilateral trades negotiated by the RTO or ISO.

[35] Comverge at 13–14. Similarly, it is not clear to the Commission what service Comverge is referring to, as Scarcity Pricing is not an ancillary service.

[36] Xcel at 7.

[37] Allied Public Interest Groups at 1.

[38] NARUC at 7. The proposal for ancillary services market states: ''The Commission proposed to obligate each RTO or ISO to accept bids from demand response resources, on a basis comparable to any other resources, for ancillary services that are acquired in a competitive bidding process, if the demand response resources (1) are technically capable of providing the ancillary service and meet the necessary technical requirements, and (2) submit a bid under the generally-applicable bidding rules at or below the market-clearing price, *unless the laws or regulations of the relevant electric retail regulatory authority do not permit a retail customer to participate.''* NOPR, FERC Stats. & Regs. ¶ 32,628 at P 56 (emphasis added).

[39] Pennsylvania PUC at 11.

[40] *See, e.g.*, Comverge at 17; Dominion at 4; and SoCal Edison-SDG&E at 3.

[41] Dominion at 4.

[42] Comverge at 17.

[43] SoCal Edison-SDG&E at 3.

that any such preferential treatment could lead to overall increases in costs to customers through the subsidization of demand response.[44] Therefore, Midwest Energy asks that the Commission require that: (1) each RTO or ISO demand response program be subject to a net-benefits test and (2) all demand-side resources be subject to a performance evaluation.[45]

30. Reliant comments that demand response resources should be subject to penalties for non-performance comparable to those that supply resources face. Reliant also states that demand response resources that supply ancillary services should participate in RTO and ISO ancillary services markets primarily via the entity that schedules and financially settles the load for their meters.[46] Allied Public Interest Groups agrees that demand response resources should face comparable penalties for non-performance, but notes in reply comments that ''comparable'' penalties does not mean ''the same'' penalties.[47]

31. Public Interest Organizations urge the Commission to expand the demand response provisions to include energy efficiency resources, environmentally benign behind-the-meter distributed generation, and all other demand-side resources that are capable of providing the service.[48] Public Interest Organizations explain in their comments that ''energy efficient resources produce load reductions for the length of their measured lives, relieving congestion, reducing market costs, and increasing system reliability.'' They state that ''a bundle of energy efficient resources that reduces energy use on a large scale—an 'efficiency power plant' or EPP—can achieve energy savings that are just as predictable and substantial as the energy output of a conventional power plant. The consistent savings from these energy efficiency programs and investments can be thought of as a virtual power plant.''[49] Allied Public Interest Groups assert that the comparable treatment proposed for demand response in the NOPR should be expanded to cover all reliable and efficient demand response resources that are technically capable of providing the service needed. Allied Public Interest Groups notes that limiting participation in ancillary services markets to ''traditional'' demand response resources may unintentionally exclude innovative new technologies that can help achieve goals of system reliability and efficiency.[50]

32. TAPS asserts that behind-the-meter generation can perform as a demand resource in ancillary services markets. TAPS states that the regulatory language should be modified to include this type of resources as well as reliability-based demand response. They note that reliability-based demand response, or demand response that is not in reaction to an increase in the price of electric energy or to incentive payments, is currently not included in the regulatory definition of Demand Response contained within this proceeding.[51]

33. Some supporters state that the Commission should address in the Final Rule compensation for demand response resources. For instance, Industrial Consumers suggest that the payment structure for demand response resources should be comparable to the payment of a generator.[52] They also note that to promote the development of demand response resources and fairly compensate these resources for their ancillary services, a methodology for calculating and accurately representing customer baselines must be developed on a consistent basis.[53] EnerNOC agrees and asks the Commission to require RTOs and ISOs to demonstrate in future compliance filings that customer baseline methodologies appropriately address concerns of accuracy, integrity, and comparable treatment of demand response resources.[54]

34. E.ON U.S. does not support the Commission's proposal. E.ON U.S. believes that the Commission's proposal mandates the purchase of demand response products regardless of price, and that such a practice will distort the market and create additional costs for end-use customers.[55] E.ON U.S. argues that the Commission should only require comparable treatment of demand response resources and not place any extra emphasis or incentive on their use.

35. Several commenters request that the Commission develop a *pro forma* tariff regarding demand response participation in ancillary services markets. Industrial Consumers argue that the Commission should prescribe specific *pro forma* tariff language for RTOs and ISOs to adopt within 30 days of the Final Rule's effective date. Otherwise, they assert that piecemeal implementation by RTOs and ISOs may result in delay, inefficiency, and inconsistency.[56] Similarly, Industrial Coalitions state that the Commission should incorporate into a *pro forma* demand response tariff appropriate minimum standards to enable demand response resources to provide, and be comparably compensated for, ancillary services. Industrial Coalitions and Steel Manufacturers contend that the Commission should obligate RTOs and ISOs to demonstrate that their own tariffs are consistent with or superior to the *pro forma* provisions and any deviations from the *pro forma* tariff should only be permitted if they can provide a clear justification for doing so.[57]

36. A few commenters express concern about the Western Electricity Coordinating Council's (WECC) regional reliability standard addressing operating reserve requirements because WECC currently allows demand response to supply only non-spinning reserves.[58] For example, CAISO points out that WECC's standard is inconsistent with the Commission's directive in Order No. 890 that a transmission provider must permit non-generation resources to provide ancillary services to the extent they are capable of doing so. It argues that WECC is non-compliant with Order No. 693, which includes a requirement explicitly providing that demand-side management may be used as a resource for contingency reserves. Therefore, CAISO comments that the Commission should direct the Electric Reliability Organization (ERO) to effect a change in WECC requirements.[59]

37. Several entities ask that the Final Rule not disturb or replace ongoing proceedings in individual regions. Midwest ISO states that the Commission recently approved its integration of demand response resources to participate in Midwest ISO ancillary services markets, on a basis comparable to other resources (ASM Proposal).[60] Given this, Midwest ISO requests that the Commission find that its ASM Proposal satisfies the NOPR's

[44] Midwest Energy at 3.

[45] *Id.*

[46] Reliant at 4.

[47] Allied Public Interest Groups at 4.

[48] Public Interest Organizations at 4.

[49] *Id.* at 13–14.

[50] Allied Public Interest Groups at 7.

[51] TAPS at 9.

[52] Industrial Consumers at 13.

[53] *Id.* at 14.

[54] EnerNOC at 11.

[55] E.ON U.S. at 14.

[56] Industrial Consumers at 7–8. Industrial Consumers note that the Commission's practice extending back to Order No. 888 has been to standardize rules and procedures for generators and other transmission users with the *pro forma* OATT as necessary to promote consistency and to avoid undue discrimination. *Id.*

[57] Industrial Coalitions at 11; Steel Manufacturers at 10.

[58] California DWR at 8; CAISO at 5; California PUC at 9–10; and PG&E at 6–7.

[59] CAISO at 5; *see also* California PUC at 10.

[60] *Midwest Independent Transmission System Operator, Inc.*, 112 FERC ¶ 61,283 (2005), *order on reh'g*, 123 FERC ¶ 61,297 (2008) (ASM Order).

requirement that each RTO and ISO submit for Commission approval standards by which demand response resources are able to participate and bid in the ancillary service markets on comparable terms as other resources.[61] CAISO states that it will comply with the NOPR requirement in the Release 1A enhancements to its Markets Redesign & Technology Upgrade (MRTU).[62] It asks the Commission to clarify that it does not intend to replace the specific schedule that it has accepted for the CAISO's implementation of MRTU with the generic compliance schedule proposed in the NOPR.[63]

38. In addition, while Maine PUC agrees that demand response is important to the efficient functioning of wholesale electric markets, it states that the Commission should allow ISO New England to work with state regulators and NEPOOL Participants to make existing programs more robust and to eliminate barriers to demand response participation.[64] Maine PUC notes that demand response programs in New England are achieving price savings and reducing the need for additional generation and transmission, demonstrated by the significant participation of demand response resources in the forward capacity market. Therefore, Maine PUC states that the Commission should not impose the NOPR's specific requirements for demand response on ISO New England.

39. SPP states that it does not currently have an ancillary services market; however, it reports that consideration and incorporation of demand response in future market development is currently being undertaken by SPP's Working Groups and Task Forces.[65]

40. Alcoa maintains that the Commission's proposal is well-intended, but falls short of what is needed to ensure non-discriminatory treatment of demand response bids by industrial customers. Alcoa asserts that the Commission's proposal is incomplete because it relies too heavily on vague concepts such as comparability of resources and reasonable requirements to increase access to ancillary services. Alcoa argues that there should be no restriction on the amount of participation by demand response resources in organized wholesale markets, and suggests that, at a minimum, regional operators should be required to justify such restrictions to the Commission and demonstrate that they are necessary for technical reasons.[66]

41. Several commenters support the Commission's conclusion that it is not appropriate for the Commission to develop a standardized set of technical requirements.[67] California PUC stresses the importance of allowing RTOs and ISOs the flexibility to modify requirements in the future, as experience is gained with demand response programs. EEI believes that standardization of these requirements could result in unnecessary expense and delay in implementation by requiring incompatible infrastructure across different RTOs and ISOs. EnerNOC believes that the Commission struck the appropriate balance by requiring coordination among the RTOs and ISOs without mandating standardization.

42. North Carolina Electric Membership states that the Commission should require RTOs and ISOs to develop technical requirements in conjunction with stakeholders to ensure that all interests are properly considered. Old Dominion also states that any standards developed in response to the Commission's requirement should be comprehensive and result from a stakeholder process.

43. LPPC supports the Commission's recognition that demand response resources must be technically capable of providing ancillary services. In addition, LPPC agrees with the Commission's statement that RTOs and ISOs need to impose requirements on telemetry and metering to allow demand response resources to fully participate in ancillary services markets. LPPC adds that an important element of any RTO- or ISO-led ancillary services program must be performance monitoring to ensure that demand response resources truly respond when called upon.[68] Also, Old Dominion argues that the ability to accurately measure and verify demand response is necessary to guarantee that these resources are providing real benefits to the market.[69]

44. APPA supports the Commission's overall proposal, but states that the Commission should recognize that metering, telemetry and performance requirements that may have to be imposed on demand-side resources to ensure their reliable performance will be more stringent than the requirements most retail customers are used to accommodating. APPA questions whether end-use customers will offer ancillary services that may require them to reduce consumption substantially on very short notice. APPA asserts that program participants may drop out when called upon too frequently. APPA states that it may prove difficult to reconcile the rigorous technical requirements for end users necessitated by the instantaneous nature of certain ancillary services with the desire of many larger loads for reliability, flexibility and convenience.[70]

45. NYISO recommends that the Final Rule clarify the NOPR's proposed regulatory language to specify that demand response resources must also meet applicable reliability requirements before they are permitted to bid into markets.[71] NYISO states that this language would clearly articulate the Commission's support for the integration of demand resources into ancillary services markets without overriding requirements adopted by NERC or the New York State Reliability Council. Further, it notes that this approach would be consistent with Order 890–A, which allows RTOs and ISOs to adopt reasonable reliability related limitations on demand resource participation.[72]

46. Comverge requests that the Commission ensure that any requirements imposed on demand response resources are not overly technical and burdensome.[73] California PUC states that telemetry, for example, is necessary for resources offering ancillary services, but a telemetry requirement for every participant (such as small commercial and residential customers) may be excessive and could erect a barrier to entry for these smaller customers, particularly when not every demand response supplier has the money to install real-time telemetry and metering.[74] EnerNOC also mentions this concern, and asks that the Commission clarify that its ''reasonableness'' requirement is aimed at ensuring that reasonable technical requirements not be unduly restrictive on demand response resources, such as those that may add unwarranted and unnecessary costs to participation. EnerNOC states that technical standards should focus on the reliability parameters of the

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[61] Midwest ISO at 9.

[62] *Cal. Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274 (2006), *order on reh'g*, 119 FERC ¶ 61,076 (2007).

[63] CAISO at 2–4.

[64] Maine PUC at 3–4.

[65] SPP at 5.

[66] Alcoa at 2–3.

[67] *E.g.*, California PUC at 9; EEI at 12; EnerNOC at 9; NYISO at 6; and North Carolina Electric Membership at 4.

[68] LPPC at 6–7.

[69] Old Dominion at 7.

[70] APPA at 33–34.

[71] NYISO at 5–6.

[72] *Id.* at 6 (citing Order No. 890–A, 73 FR 2984 (Jan. 16, 2008), FERC Stats. & Regs. ¶ 31,261 at P 499).

[73] Comverge at 13.

[74] California PUC at 11.

particular ancillary service and allowing demand response resources to utilize alternative methods to meet these standards.[75]

ii. Commission Determination

47. In this Final Rule, the Commission adopts the NOPR proposal to require each RTO or ISO to accept bids from demand response resources, on a basis comparable to any other resources, for ancillary services that are acquired in a competitive bidding process, if the demand response resources: (1) are technically capable of providing the ancillary service and meet the necessary technical requirements; and (2) submit a bid under the generally-applicable bidding rules at or below the market-clearing price, unless the laws or regulations of the relevant electric retail regulatory authority do not permit a retail customer to participate. All accepted bids would receive the market-clearing price.

48. The Commission's policy has been, and continues to be, to identify and eliminate barriers to participation of demand response resources in organized power markets. Development of demand response resources provides benefits to consumers by providing competitive pressure to reduce wholesale power prices, providing for the more efficient operation of organized markets, helping to mitigate market power and enhance system reliability, and encouraging development and implementation of new technologies, including renewable energy and energy efficiency resources, distributed generation and advanced metering. The reforms implemented in this Final Rule will benefit energy consumers by removing several barriers to the development and use of demand response resources in organized wholesale electric power markets.

49. As noted in the NOPR, this requirement would apply to competitively-bid markets, if any, for energy imbalance, spinning reserves, supplemental reserves, reactive supply and voltage control, and regulation and frequency response as defined in the *pro forma* OATT, or to the markets of their functional equivalents in an RTO or ISO tariff.[76] The Commission requires that demand response resources that are technically capable of providing the ancillary service within the response time requirements,[77] and that meet reasonable requirements adopted by the RTO or ISO as to size, telemetry, metering and bidding, be eligible to bid to supply energy imbalance, spinning reserves, supplemental reserves, reactive and voltage control, and regulation and frequency response.[78]

50. In response to Allied Public Interest Groups, we decline to define ''comparable treatment.'' Each RTO and ISO is unique, and the Commission hesitates to impose a uniform definition. Each RTO and ISO therefore should establish policies and procedures in cooperation with its customers and other stakeholders that ensure that demand response resources are treated comparably to supply-side resources. The Commission will have ample opportunity to evaluate concerns that may arise when it reviews the compliance filings required by this Final Rule.

51. In light of APPA's comments, we clarify that this requirement applies only to competitively-bid markets for those ancillary services specified, as well as to the markets of their functional equivalents in an RTO or ISO tariff. This requirement does not obligate RTOs or ISOs to create new competitively-bid ancillary services markets.

52. In response to Xcel and E.ON U.S., we note that the Commission proposed in the NOPR to obligate RTOs and ISOs to accept bids from demand response resources on a comparable basis to supply resources for ancillary services. For Xcel, we clarify that demand response providers are not required to offer potential demand response into the ancillary services markets. Demand response resources may evaluate market prices and other factors before making a determination to bid or not. Regarding E.ON U.S.'s comments, the Commission did not propose (and does not require) that RTOs or ISOs must purchase ancillary services from demand response resources without regard to whether these resources are lower-bid alternatives to supply resources.

53. In response to NARUC and others who comment that the Commission's proposal would place the burden on retail regulatory authorities to show that a demand response proposal conflicts with state or local laws or regulations, we clarify that we will not require a retail regulatory authority to make any showing or take any action in compliance with this rule.[79] Rather, this rule merely requires an RTO or ISO to accept bids for ancillary services from demand response resources, unless the laws or regulations of the relevant electric retail regulatory authority do not permit a retail customer to participate.

54. We disagree with commenters who argue that requiring RTOs and ISOs to allow demand response resources to participate in ancillary services markets may be counterproductive or unnecessary.[80] This requirement removes a barrier to participation of demand response resources in organized wholesale markets and allows these resources to provide ancillary services on a basis comparable to generation sources. This requirement would potentially expand the resource pool in these organized markets, thereby lowering the overall market price for ancillary services, as well as potentially mitigating the exercise of market power. The competitiveness within ancillary services markets, as well as the system reliability, would be enhanced through increased participation.

55. Contrary to Midwest Energy's comments, we do not find that this requirement will lead to any preferential treatment for demand response resources or supply-side resources. Both sets of resources would be treated and penalized comparably in instances of non-performance.

56. In response to Public Interest Organizations, the Commission has not excluded from eligibility any type of resource that is technically capable of providing the ancillary service, including a load serving entity's (LSE) or eligible retail customer's behind-the-meter generation or any other demand response resource. Further, the Commission appreciates the value of energy efficiency, and is aware of RTO and ISO efforts to integrate energy efficiency into organized markets. Nothing in this rule precludes an RTO or ISO from appropriately including energy efficiency into any of its markets. The Commission did not propose to include energy efficiency as a provider

[75] EnerNOC at 10–11.

[76] NOPR, FERC Stats. & Regs. ¶ 32,628 at P 56.

[77] Some technologies may be capable of responding to an RTO's or ISO's control signal and providing certain ancillary services, such as regulation and frequency response service, more quickly than under existing response time requirements.

[78] The RTO or ISO may specify certain requirements, such as registration with the RTO or ISO, creditworthiness requirements, and certification that participation is not precluded by the relevant electric retail regulatory authority. The RTO or ISO should not be in the position of interpreting the laws or regulations of a relevant electric retail regulatory authority.

[79] In reply to the Pennsylvania PUC's recommendation that the Commission continue to work with state authorities to eliminate barriers to demand response, we note that NARUC and the Commission, through their Demand Response Collaborative, are working to outline options to coordinate retail and wholesale regulatory policies in order to stimulate participation in demand response by reducing or eliminating jurisdictional barriers.

[80] The Commission has approved actions by some RTOs and ISOs to incorporate demand response into their ancillary services markets. *See, e.g.*, *California Indep. Sys. Operator*, 116 FERC ¶ 61,274 (2006); *PJM Interconnection, LLC*, 114 FERC ¶ 61,201 (2006).

of competitively procured ancillary services, and does not have an adequate record to address this issue here.

57. With regard to Industrial Consumers' and EnerNOC's comments requesting the resolution of customer baseline issues, the Commission agrees that customer baselines are an important factor in the appropriate compensation for demand response resources. Customer baselines are designed to depict, as accurately as possible, a customer's normal load on a given day. Establishing this baseline helps system operators to measure and verify load reductions, thus giving RTOs and ISOs the ability to not only determine if demand response resources showed up, but also what the proper value of the demand reduction should be. Many RTOs and ISOs currently establish such bidder baselines as part of their demand response programs, or they are working with their stakeholders to modify such methodologies. Accordingly, RTOs and ISOs should describe in their compliance filings their efforts to develop adequate customer baselines.

58. Regarding comments related to WECC's provisions for demand response resources in its reliability standards, we note that this rule requires comparable treatment for demand response resource participation in ancillary services markets. This is a general rulemaking and is not the proper venue for adjudicating the alleged issue regarding WECC's regional reliability standards.[81]

59. In response to comments, the Commission again finds that it is not appropriate in this rulemaking to develop a standardized set of technical requirements for demand response resources participating in ancillary services markets. Instead, the Commission will allow each RTO and ISO, in conjunction with its stakeholders, to develop its own minimum requirements. However, as proposed in the NOPR, the Commission will require RTOs and ISOs to coordinate with each other in the development of such technical requirements, and provide the Commission with a technical and factual basis for any necessary regional variations.[82] In addition, having RTOs and ISOs work in conjunction with stakeholders as well as with each other should ensure that any developed requirement is not so full of technical detail or so burdensome that it discourages demand response resource participation.

60. With respect to NYISO's request that the Commission clarify its proposed regulatory language to specify that demand response resources must also meet ''applicable reliability requirements,'' the Commission does not see a need to include this provision in this Final Rule. To do so would merely duplicate existing regulations that require reliability standards, and that set out certain reliability requirements. This duplication would serve no useful purpose.

61. As part of the compliance filing to be submitted within six months of the Final Rule, each RTO or ISO is required to file a proposal to adopt reasonable standards necessary for system operators to call on demand response resources, and mechanisms to measure, verify, and ensure compliance with any such standards. These standards would be subject to Commission approval.

62. The Commission is mindful of the progress being made in California with MRTU and in the Midwest ISO with its ASM Order. Our requirement is that, where there are markets for acquiring ancillary services, these markets must be open to qualified demand response bidders. This requirement allows each RTO or ISO to work with stakeholders to develop the appropriate implementation rules for its own market design. This approach allows for regional variation and should alleviate the concerns of Midwest ISO, CAISO, and Maine PUC.

63. The Commission will not now rule on CAISO's request that the Commission not interfere with its current timeline to implement MRTU, or Midwest ISO's request that the Commission find Midwest ISO already satisfies the proposed requirements through its ASM Proposal. CAISO and Midwest ISO must submit, within their respective compliance filings, a description of how their current activities comply with the requirements of this Final Rule. Upon review, the Commission will determine if further action on behalf of either RTO or ISO is necessary.

b. New Bidding Parameters

64. The Commission proposed to require RTOs and ISOs to allow demand response resources to specify limits on the frequency and duration of their service in their bids to provide ancillary services—or their bids into the joint energy-ancillary services market in the co-optimized RTO markets.[83] These limits would include a maximum duration for dispatch, a maximum number of times per day that demand response resources could be called, or a maximum amount of energy per day or week that a resource can produce.

65. The Commission requested comment on this proposed requirement and whether these new parameters should be available for all bidders, not just for demand response resources. Further, the Commission intended that the bidding parameters would be implemented by all RTOs and ISOs, and proposed to require them to confer with each other and to provide a technical and factual basis for any necessary regional variations.

i. Comments

66. Most commenters support the Commission's proposal to require RTOs and ISOs to incorporate new parameters into their bidding rules to allow demand response resources to specify in their bids the duration and frequency of their service.[84] For instance, several commenters state that allowing new bidding parameters would increase the number and type of demand response resources participating in the ancillary services markets.[85] Some commenters note that generators face certain constraints (including start-up costs, ramp rates, and limits on the number of hours that they may operate efficiently), which are reflected within their bids. They assert that allowing demand response resources to specify similar constraints within their bids is consistent with the Commission's principle of comparability between demand-side and supply-side resources.[86] DC Energy states that, similar to generators, demand response providers should have the choice to

[81] Concerns regarding WECC's regional reliability standards can be addressed by filing a complaint under section 206 of the FPA, 16 U.S.C. 824e, or by filing a notice under section 215 of the FPA, 16. U.S.C. 824o. Under section 215, ''[i]f a user, owner or operator of the transmission facilities of a Transmission Organization determines that a [r]eliablity [s]tandard may conflict with a function, rule, order, tariff, rate schedule, or agreement accepted, approved, or ordered by the Commission * * *. the Transmission Organization shall expeditiously notify the Commission * * *.'' 18 CFR 39.6.

[82] NOPR, FERC Stats. & Regs. ¶ 32,628 at P 64.

[83] *Id.* P 62.

[84] *E.g.,* Ameren; American Forest; APPA; BlueStar Energy; Beacon Power; Mr. Borlick; BP Energy; California DWR; California PUC; Cogeneration Parties; Comverge; DC Energy; Detroit Edison; DRAM; Duke Energy; EEI; EnergyConnect; EnerNOC; Exelon; FTC; First Energy; Industrial Coalitions; Industrial Consumers; ISO New England; ISO/RTO Council; Midwest ISO; North Carolina Electric Membership; Ohio PUC; Old Dominion; Organization of Midwest ISO States; PG&E; Public Interest Organizations; Reliant; Steel Producers; TAPS; Wal-Mart; and Xcel.

[85] *E.g.,* American Forest at 5; Exelon at 5.

[86] American Forest at 5; Cogeneration Parties at 3; DRAM at 6–7; Duke Energyat 3–4; Exelon at 5–6; FTC at 25–27; FirstEnergy at 7; Industrial Consumers at 12; ISO/RTO Council at 4; North Carolina Electric Membership at 4; Old Dominion at 8; and Public Interest Organizations at 6.

observe market signals and make an informed decision on whether to bid into these markets.[87]

67. The ISO/RTO Council asserts that the implementation of these new bidding parameters must be done in a way that assures demand response resources participating in ancillary services markets meet the same product requirements as supply-side resources.[88] Several commenters express their support for this concept provided that demand response resources are not afforded an undue advantage over supply-side resources.[89]

68. Two commenters state that they support the proposal provided that certain conditions are met. Ameren states there should be no adverse effect on system reliability and that any market rules that provide this flexibility should be limited in scope so as to avoid the potential for gaming.[90] BP Energy agrees with the Commission's proposal only to the extent that bidding parameters submitted by demand response resources can be incorporated into the RTO and ISO software in a cost effective manner while maintaining the algorithm's ability to perform timely cost minimizing optimizations.[91]

69. ISO New England supports granting individual demand response resources the opportunity to specify additional bidding parameters, but notes that such specification may limit the resource's qualification (under market rules) on an individual basis to bid to supply operating reserves.[92] However, ISO New England itself notes that demand response aggregators should be in a position to formulate bids combining individual demand resources so as to be able to meet the reserves market's availability requirements in a manner comparable to that of generation.

70. Duke Energy notes that the NOPR proposal would allow demand response resources to manage the risk that they would be called upon too frequently or for too long a period relative to their individual constraints. In that respect, Duke Energy asserts that if RTOs and ISOs are not required to account for such bid flexibility, demand resources could potentially be eliminated from the ancillary services markets through voluntary means.[93] Duke Energy argues that without any knowledge of how and when they will be used, demand resources may view the ancillary services markets as too risky and, therefore, not participate in them. APPA states that large end-use customers' desire to reduce consumption on short notice decreases the more frequently they are called upon.[94]

71. Steel Producers asserts that demand response resources' unique characteristics need to be taken into account, and recommends that the Commission require RTOs and ISOs to allow, at a minimum, the following optional bidding parameters in addition to the three mentioned in the NOPR: (1) Minimum notice requirement; (2) minimum/maximum shut-down time; (3) minimum duration for dispatch; (4) targeted demand reduction level; (5) bids ''down to'' a designated megawatt level; and (6) guaranteed minimum LMP.[95]

72. Similarly, California PUC requests that the Commission expand its proposal to include all demand response resource bids in all aspects of wholesale markets, and also permit each demand resource bidder to submit, as part of its bid and a master file, its output constraints such as minimum load reduction, minimum load, load reduction initiation time, minimum load reduction time, maximum load reduction time, minimum base load time, maximum number of daily load curtailments, minimum and maximum daily energy limits, load pick up rate, load drop rate, load reduction initiation cost, and minimum load reduction cost.[96]

73. Multiple commenters argue for a regional approach in implementing the Commission's proposal.[97] For instance, EEI and Detroit Edison state that they support the Commission's proposal provided that RTOs and ISOs can establish lower or minimum limits for such service.[98] EEI asks that RTOs and ISOs be allowed to specify the minimum duration in hours or minimum number of times per day or week that a resource may be called upon. Duke Energy states that the specific bid parameters, as well as the methodologies and procedures that RTOs and ISOs use to implement the Commission's proposal, should be developed on a regional basis within their stakeholder processes, rather than through a Commission-imposed uniform requirement in the Final Rule.[99] NYISO also contends that a regional approach is appropriate because specifying bidding parameters in the regulations may prove problematic in the future as regional market designs continue to evolve.[100] Exelon agrees with the Commission that minimum requirements for bidding parameters should not be prescribed by the Commission in this rulemaking, but rather should be developed by RTOs and ISOs. Exelon also supports the Commission's proposed requirement that RTOs and ISOs provide justification for any necessary regional variations.[101] EnerNOC believes the Commission, by requiring coordination and justification for variations, without mandating standardization, has articulated the correct compromise.[102]

74. Midwest ISO and CAISO state that their market designs already satisfy the NOPR's proposed bidding parameters requirement. Midwest ISO states that it developed its bidding parameters through the stakeholder process and that the parameters were approved by the Commission within its ASM Order.[103] Therefore, Midwest ISO asks that the Commission find that its ASM proposal satisfies the NOPR's requirement regarding bidding parameters. Similarly, CAISO states that it is developing its ancillary services market and it will comply with the proposed bidding parameters in the Release 1A enhancements to MRTU.[104]

75. Further, several commenters support making additional parameters available for all bidders, to include both demand and supply resources.[105] Wal-Mart states that comparable rules could apply to supply resources as long as neither supply nor demand resources are provided with an advantage.[106] Old Dominion states that all resources bidding into the ancillary services markets should be susceptible to the same penalties, performance and reliability requirements.[107] Exelon states that as long as the specification of operational limitations does not impair

[87] DC Energy at 4.

[88] ISO/RTO Council at 4.

[89] *E.g.,* Old Dominion at 8; Reliant at 4; and Wal-Mart at 5.

[90] Ameren at 18.

[91] BP Energy at 14.

[92] ISO New England at 5.

[93] Duke Energy at 3–4.

[94] APPA at 36–37.

[95] Steel Producers at 4–5.

[96] California PUC at 13–14.

[97] *E.g.,* EEI; Detroit Edison; Duke Energy; ISO/RTO Council; North Carolina Electric Membership; NYISO; and Kansas CC.

[98] EEI at 13; Detroit Edison at 2–3.

[99] Duke Energy at 4.

[100] NYISO at 6.

[101] Exelon at 6.

[102] EnerNOC at 9.

[103] Midwest ISO at 10. Midwest ISO states that its tariff allows market participants (both generators and demand response resources) to specify hourly ramp rates, hourly economic minimum and maximum limits, hourly regulation minimum and maximum limits, minimum and maximum run times, as well as a maximum start-up limit, which establishes the maximum number of times the resource can be called upon within a twenty-four-hour period.

[104] CAISO at 2.

[105] *E.g.,* California DWR at 12; Duke Energy at 4; EEI at 14; EnerNOC at 8; Exelon at 6; Midwest ISO at 10; Reliant at 4; and Wal-Mart at 5.

[106] Wal-Mart at 5.

[107] Old Dominion at 8.

market efficiency, demand and supply resources should be treated on a comparable basis because they provide reliable and efficient capacity to RTOs and ISOs.[108]

76. The California DWR supports making new parameters available to all resources because certain facilities have a specific purpose that is distinct from sales to, or support of, the electric grid. For instance, hydroelectric generation sites must satisfy water storage, water delivery, and related operational requirements. The California DWR asserts that any RTO or ISO requirements must accommodate this primary purpose for these resources.[109]

77. Several commenters state that new bidding parameters should not be available to all resources.[110] For instance, TAPS states that there is already ample bidding flexibility for generators, and it is concerned about the possibility of creating unintended consequences such as new gaming opportunities. APPA states that RTO and ISO ancillary services markets are already complex and accommodating additional bid parameters for generators in their software and problem solving algorithms would make the markets even more complicated. Although EEI is in agreement with making new bidding parameters available for all bids, it is concerned that applying the new parameters to generation resources without evaluating the implications could result in creating unintended incentives. Therefore, EEI suggests that RTOs and ISOs should not be required to apply the new parameters across all generating resources as long as they provide justification for treating some generating resources differently.

78. Finally, among the supporters of this proposal, EEI states that the addition of new parameters to bidding rules must not result in any fundamental change to existing market designs or affect the efficiencies of co-optimized markets.[111]

79. Several commenters state that demand response providers should be allowed to sell into the ancillary services markets without being required to sell into the energy market.[112] Comverge is in favor of this, but notes that demand response providers should also be allowed to sell into the energy market on a voluntary basis. Beacon Power states that a generator is always capable of supplying energy and, therefore, does not face the financial risks and barriers that a non-generator faces if it is forced to bid into the energy market.

80. NEPOOL Participants opposes the Commission's proposal to implement new bidding parameters for demand response resources. NEPOOL Participants states that each region needs an opportunity to evaluate this issue more fully and consider whether bidding limits are the most appropriate solution and whether such limits or other reforms should be restricted to just demand response or include other kinds of resources. It asserts that any change in bidding requirements needs to ensure comparability with others resources and that system reliability is maintained.[113] Maine PUC agrees.[114]

ii. Commission Determination

81. The Commission determines that each RTO and ISO is required to allow demand response resources to specify limits on the duration, frequency and amount of their service in their bids to provide ancillary services—or their bids into the joint energy-ancillary services markets in the co-optimized RTO markets. As noted in the NOPR (and several commenters agree), these limits are comparable to the limits generators may specify on price, quantity, startup and no-load costs, and minimum downtime between starts.[115] All RTOs and ISOs must incorporate new parameters into their ancillary services bidding rules that allow demand response resources to specify a maximum duration in hours that the demand response resource may be dispatched, a maximum number of times that the demand response resource may be dispatched during a day, and a maximum amount of electric energy reduction that the demand response resource may be required to provide either daily or weekly.

82. This requirement eliminates a major barrier to participation of demand response resources in ancillary services markets by ensuring that demand response resources are treated comparably to supply-side resources. In this regard, the Commission agrees with comments from APPA, Duke Energy, and others that argue that the desire of many end-use customers to reduce their consumption levels on short notice may decrease the more frequently they are called upon. This requirement would allow those customers to limit the frequency with which they are called upon to reduce demand, and thus make it more economically beneficial for these resources to participate in ancillary services markets.

83. The Commission's requirement also enhances competition within ancillary services markets. With demand response resources able to specify the duration, frequency and amount of their service, ancillary services markets will become more attractive for such resources. Increased participation in the market will result in an expanded pool of available resources, thereby potentially improving demand elasticity and system reliability, as well as lessening price volatility.

84. The Commission also finds that this requirement removes barriers to the comparable treatment of demand-side and supply-side resources. Generators include operational constraints in their bids, and permitting demand response resources to do the same results in the comparable treatment of both supply-side and demand-side resources. However, in keeping with this effort of greater comparability, the Commission determines that implementation of its requirement by RTOs and ISOs should not lead to either demand-side or supply-side resources being afforded an undue advantage within ancillary services markets.

85. In the NOPR, the Commission requested comment on whether other bidding parameters should be considered.[116] The Commission noted that any proposed parameters must not have the effect of creating an undue preference for demand response resources. The Commission does not have a sufficient record here to assess whether the proposed additional bidding parameters submitted by the California PUC and Steel Producers may offer demand response resources greater flexibility within their bids as compared to the bids of generators. For this reason the Commission will not accept the proposed additional bidding parameters on a generic basis for all RTOs and ISOs in this rulemaking. Rather, individual RTOs and ISOs are free to propose additional parameters in their compliance filings, as long as they do not provide undue preference to demand response resources vis-a-vis supply-side resources, and interested persons may raise these additional parameters with their deliberations with the individual RTOs and ISOs.

86. In the NOPR, the Commission stated that it was not appropriate for the Commission to develop in a rulemaking a standardized set of minimum requirements for minimum size bids, measurement, telemetry and other

[108] Exelon at 5–6.

[109] California DWR at 12–13.

[110] *E.g.,* APPA at 37; Mr. Borlick at 2; and TAPS at 8.

[111] EEI at 14.

[112] *E.g.,* Beacon Power at 9; Comverge at 12; and Wal-Mart at 5.

[113] NEPOOL Participants at 11–12.

[114] Maine PUC at 3–4.

[115] NOPR, FERC Stats. & Regs. ¶ 32,628 at P 62.

[116] *Id.* P 64.

factors, and instead allowed RTOs and ISOs to develop their own minimum requirements, including bidding parameters.[117] The Commission adopts this position in this Final Rule. RTOs and ISOs must incorporate bidding parameters that allow demand response resources to specify limitations on the duration, frequency and amount of their service. However, the development of specific parameters and the methods used to implement the Commission's requirement are the responsibility of the RTOs and ISOs, in consultation with their respective stakeholders. RTOs and ISOs are also required to confer with each other on such parameters and methods and to provide a technical and factual basis for any necessary regional variations. This approach adequately accounts for regional variation between the RTOs and ISOs and alleviates the concerns of those commenters requesting regional flexibility in implementing the Commission's requirement.

87. Midwest ISO asks that the Commission find that it already complies with the additional bidding parameters requirement of the Final Rule. Similarly, the California ISO asserts that it will also be compliant with the requirement upon Release 1A in its MRTU process. The Commission does not intend to interrupt the progress being made in either region. However, as indicated above, the Commission will not at this time determine that either region satisfies the Commission's requirement obligating RTOs and ISOs to incorporate new bidding parameters for demand response resources, and instead will wait until each region submits its necessary compliance filing.

88. In the NOPR, the Commission requested comment on whether these additional parameters should be available for all bids, or for demand response bids only. In light of the comments received, the Commission determines that new requirements for bidding rules allowing demand response resources to specify the duration, frequency and amount of their service pertain only to demand response resources. Individual RTOs and ISOs are free to propose to apply them more broadly. While the Commission understands that making these new parameters available for all resources could benefit hydropower resources and other environmentally restricted, or run-time limited resources, the Commission agrees with TAPS and others that there is already sufficient bidding flexibility afforded to generators, and is concerned about the possibility of creating unintended consequences. For these reasons, at this time the Commission will not require an RTO or ISO to make these new bidding parameters available for all resources.

89. With regard to comments that demand response providers should be allowed to sell into the ancillary services markets without being required to sell into the energy market, the Commission notes that the ANOPR proposal permitting such action was removed at the NOPR stage, and replaced with a proposal to allow demand response resources to specify limitations on the duration, frequency and amount of their service.[118] The Commission had received comments previously that argued that allowing demand response resources to bid into the ancillary services markets without also bidding into the energy markets could upset certain market efficiencies in co-optimized markets. Therefore, the Commission put forth a compromise proposal, which allows demand response resources to specify operational limits in their bids as a way for these resources to minimize the risk that they are called on too frequently, thereby making participation in ancillary services markets more feasible. No one has persuaded us otherwise; therefore, the Commission will adopt this provision from the NOPR.

c. Small Demand Response Resource Assessment

90. The NOPR proposed to direct RTOs and ISOs to assess the value and technical feasibility of small demand response resources providing ancillary services one year from the effective date of the Final Rule, including whether (and how) smaller demand response resources can reliably and economically provide operating reserves through pilot projects or other mechanisms.[119]

i. Comments

91. Several commenters support the NOPR proposal for small demand response resource assessment.[120] For example, Reliant states that accommodating smaller demand response resources may result in an increase in operating reserves.[121] EnerNOC believes that the assessment effort will reveal ways for smaller demand response resources to provide ancillary services while maintaining reliable operations and appropriate measurement and verification.[122] APPA believes that pilot programs could be particularly valuable in assessing technical feasibility of accommodating smaller demand-side resources.[123] It notes that accurate metering and telemetry would be significant factors in any efforts associated with this assessment, primarily because ''communication and operational performance standards applicable to demand-side resources are more demanding than the current requirements applicable to retail customers.'' Public Interest Organizations request that ''RTOs and ISOs be directed to specifically address the issue of comparable treatment of smaller loads.'' [124] Allied Public Interest Groups believe that the Commission should include in its Final Rule a directive to RTOs and ISOs to initiate pilot programs for small demand response resources similar to the ISO New England Demand Response Reserves Pilot Program.[125] In their view, pilot programs aid grid operators in determining whether a diverse portfolio of demand response resources that includes small resources can provide cost-effective and reliable ancillary services.

92. EnerNOC and DRAM indicate that technical requirements for demand response participation in ancillary services markets may act as a barrier if the technical requirements exceed what is necessary to ensure reliable electric system operations.[126] For example, they note that certain telemetry requirements may preclude smaller loads from participating in ancillary services markets. However, EnerNOC states that an assessment on how to accommodate these resources could result in reasonable standards for smaller loads that take into account the operational characteristics of such loads so as to capture their value efficiently. DRAM states that the proposed assessment should allow parties to focus on how best to modify the requirements for small demand response resource participation without creating a bias against supply-side resources.[127] Neither EnerNOC nor DRAM suggests that smaller demand response resources be allowed to participate in these markets with less stringent standards than other resources. Further, EnerNOC asserts that the small demand response resource assessment requirement should not be used as an excuse to delay currently underway pilot programs or

[117] *Id.*

[118] *Id.* P 62.

[119] *Id.* P 59.

[120] *E.g.*, APPA, Public Interest Organizations, EnerNOC; DRAM; Old Dominion; andReliant.

[121] Reliant at 4.

[122] EnerNOC at 3.

[123] APPA at 35.

[124] Public Interest Organizations at 6.

[125] Allied Public Interest Groups at 9.

[126] EnerNOC at 4; DRAM at 16.

[127] DRAM at 16.

other smaller resource reforms taking place in RTOs and ISOs. In addition, this requirement should not create an opportunity to avoid addressing barriers to smaller resource participation in ancillary services markets.[128]

93. Old Dominion supports the proposal and agrees that incorporating smaller demand response resources would be beneficial to the market, but notes that measurement and verification standards specific to these smaller resources may be necessary to ensure proper allocation of costs and to address any reliability concerns.[129]

94. Two commenters disagree on how smaller demand response resources should be defined. EnerNOC recommends that the Commission clarify that ''smaller demand response resources'' should be construed more broadly than the residential class of customers because a more diverse portfolio is more valuable to the market. EEI, however, disagrees and recommends that the Commission not define what constitutes smaller demand response resources, and instead allow each RTO or ISO to propose a definition that reflects its particular market design and characteristics.[130]

95. The ISO/RTO Council comments that its Markets Committee is already addressing certain aspects of this issue by developing a communications protocol for small demand resources, and that these efforts will be discussed at a technical conference on integrating small demand resources into organized markets. The ISO/RTO Council asserts that its report will not supplant the Commission's proposed assessment, but still urges the Commission to coalesce its proposal with the work of the ISO/RTO Council Markets Committee.[131]

96. Finally, ISO New England notes that it currently has a demand response reserve pilot program in place to assess the ability of smaller demand resources to provide reserve products to the wholesale market, and to develop comparable communication, metering, telemetry and other technical infrastructure solutions that are more suitable and cost effective for smaller, dispersed demand resources.[132]

ii. Commission Determination

97. The Commission will require RTOs and ISOs, in cooperation with their customers and other stakeholders, to perform an assessment, through pilot projects or other mechanisms, of the technical feasibility and value to the market of smaller demand response resources providing ancillary services, within one year from the effective date of the Final Rule, including whether (and how) smaller demand response resources can reliably and economically provide operating reserves and report their findings to the Commission. The choice between either a pilot program or other mechanisms in this assessment is appropriately left to the discretion of the RTO or ISO and its customers and other stakeholders. Additional issues raised here by commenters, such as the need for measurement and verification standards and a definition of what constitutes a ''small demand response resource'' should be addressed in the assessments.

98. The Commission finds that, based on the comments, accommodating smaller demand response resources through adjusted minimum size thresholds and telemetry requirements could result in an increase in potential operating reserves. Allowing more resources to participate in operating reserves and other ancillary services markets may increase the competitiveness of these markets and could lower the overall price for such services.

99. The Commission agrees that this assessment should not delay pilot programs that are currently underway or other smaller load reforms taking place in RTOs and ISOs, nor should it create an opportunity to avoid addressing barriers to smaller load participation in ancillary services markets. In addition, while not part of the Commission's requirement, the Commission encourages the ISO/RTO Council to continue developing a communications protocol for small demand response resources and encourages RTOs and ISOs to consider the ISO/RTO Council's work in developing their individual assessments.

3. Eliminating Deviation Charges During System Emergencies

a. Deviation Charges

100. The Commission proposed in the NOPR to require that all RTO and ISO tariffs be modified as necessary to eliminate a charge-referred to as a deviation charge [133]—to a buyer [134] in the energy market for taking less electric energy than it planned to take in the real-time market, during a real-time market period for which the RTO or ISO declares an operating reserve shortage or makes a generic request to reduce load to avoid an operating reserve shortage.[135]

101. The Commission proposed that an RTO or ISO must either propose amendments to its tariffs to comply with this requirement or demonstrate through a compliance filing that its existing tariff and market design meet this requirement. The Commission proposed that this filing be submitted within six months of the date that this Final Rule is published in the **Federal Register** .

102. The Commission's proposal applies to real-time demand response that occurs in addition to the demand response of participants in an RTO's or ISO's wholesale demand response program. Under the proposal, deviation charges would be eliminated only when the RTO or ISO announces an emergency situation after the close of the day-ahead market. The Commission also proposed that since deviation charges cover real costs to generators and others that are not recovered from the sale of energy in real time, these costs should be allocated to all loads of the RTO or ISO.

i. Comments

103. A majority of commenters supports the Commission's proposal and agree that eliminating deviation charges during periods when the RTO or ISO declares an operating reserve shortage or makes a generic request to reduce load to avoid an operating reserve shortage would eliminate a barrier to demand reduction in wholesale energy markets.[136] For instance, Energy Curtailment and PG&E state that penalizing an LSE for taking less energy in real-time during system

[128] EnerNOC at 6.

[129] Old Dominion at 8.

[130] EEI at 12.

[131] ISO/RTO Council at 6.

[132] ISO New England at 4.

[133] Deviation charges recover certain costs, including generators' costs (such as start-up costs) that exceed their energy market revenues when real-time demand is less than forecast. These ''uplift'' costs may include the cost of extra generators committed after the close of the day-ahead market to serve anticipated load, if those costs are not recovered from sales of energy at real-time LMPs.

[134] Examples of buyers in RTO and ISO energy markets include an LSE thatpurchases electricity to meet the load requirements of its retail customers and a retail customer that purchases electricity directly from the wholesale market.

[135] NOPR, FERC Stats. & Regs. ¶ 32,682 at P 72.

[136] Ameren at 23; American Forest at 6; APPA at 3; BlueStar Energy at 2; Mr. Borlick at 2; BP Energy at 15; California DWR at 15; CASIO at 1; California PUC at 15; Cogeneration Parties at 3; Comverge at 17; DC Energy at 5; Dominion Resources at 6; DRAM at 18; Duke Energy at 5; EEI at 14; Energy Curtailment at 4; EnerNOC at 11; Exelon at 6; FirstEnergy at 8; Industrial Coalitions at 11; Industrial Consumers at 15; Integrys Energy at 9; ISO New England at 8; ISO/RTO Council at 6; LPPC at 7; MADRI States at 6; Maine PUC at 3; Midwest Energy at 2; Midwest ISO at 11; NCPA at 5; NEPOOL Participants at 12; NIPSCO at 9; North Carolina Electric Membership at 4; Ohio PUC at 7; Old Dominion at 9; OMS at 3; OPSI at 4; Pennsylvania PUC at 11; PG&E at 8; Public Interest Organizations at 6; Reliant at 4; Steel Manufacturers at 11; Steel Producers at 5; TAPS at 9; Wal-Mart at 5; and Xcel at 8.

emergencies would be counterproductive.[137] Many commenters agree that this proposal would result in several benefits, including reduced market prices, mitigation of market power, and improved system reliability.[138]

104. Several supporters also agree with the Commission's proposal to allocate to all loads of the RTO and ISO uplift charges to cover costs associated with the elimination of such deviation charges.[139] However, NIPSCO and Old Dominion state that uplift charges should be allocated only within the zones where the emergency occurred.[140] Dominion Resources and ISO/RTO Council urge the Commission to allow each region to decide how the costs should be allocated based on market constraints and input from stakeholders.[141]

105. Several commenters seek clarification of various aspects of the proposal. For instance, EEI asks the Commission to clarify that deviation charges would be eliminated only when the RTO or ISO announces an emergency situation after the close of the day-ahead market.[142] TAPS suggests that the Commission clarify that it intends to encompass all forms of demand response that could be activated to reduce load during emergencies, including programs that operate behind the meter of the LSE with a reduction reflected in the wholesale market participant's demand.[143] Cogeneration Parties note that it is unclear whether the costs caused by uninstructed deviations during normal operations would also be incurred during a system emergency, and recommend that the Final Rule require RTOs and ISOs to verify their actual costs incurred during system emergencies before such charges are imposed on customers.[144] Similarly, Midwest Energy suggests that the net benefits for load reductions be verified before costs are imposed on customers.[145]

106. A few commenters urge the Commission to clearly define ''deviation charge'' and the circumstances under which deviation charges would be eliminated. For example, NYISO requests that the Commission clarify its proposed regulatory text to more specifically define deviation charges.[146] Others state that circumstances under which an RTO or ISO merely seeks to avoid an operating reserve shortage are significantly different from those in which it has experienced an actual operating reserve shortage or emergency. Therefore, they suggest that the Commission define the conditions when elimination of deviation charges would take place.[147] NIPSCO states that the Commission should clarify that deviation charges should also be waived when an RTO or ISO declares a NERC Energy Emergency Alert.[148] The Pennsylvania PUC states that there are two types of emergencies, generation insufficiency and generation excess, and while generation insufficiency is of greatest concern to the public, excess generation emergencies are not uncommon. At such times locational marginal price or LMP may go negative in an effort to resolve a rapidly dropping load situation. For such reasons the Pennsylvania PUC asks that the Commission clarify whether eliminating a deviation charge is appropriate for both kinds of emergencies.[149]

107. Additionally, some commenters recommend that the proposal should be expanded so that deviation charges would be eliminated not just in emergency situations, but in all situations when demand deviates from schedule by using less energy.[150] Duke urges the Commission to eliminate deviation charges so long as the load remains within an appropriate demand response ''bandwidth.'' [151] No deviation charges would be assessed in emergency or non-emergency situations, so long as the load behaves consistently with the price-sensitive demand schedule provided to the RTO or ISO. Other commenters suggest that the proposal be expanded to include other contractual arrangements,[152] demand-reduction services,[153] and programs that compensate market participants for demand reductions during system emergencies.[154]

108. Several commenters support a regional approach to establishing methods for dealing with deviation charges. For example, ISO/RTO Council urges the Commission to allow each RTO or ISO to develop its own appropriate rules to implement the proposal to account for regional operating considerations and to establish appropriate details, including defining what system conditions constitute an emergency.[155] California Munis urges regional flexibility to ensure that specific facts pertaining to each RTO or ISO can be fully considered in assessing whether this proposal will be beneficial to consumers or merely shifts costs among consumers.[156] Similarly, SoCal Edison-SDG&E state that, rather than having the Commission eliminate deviation charges in a uniform manner for all RTOs and ISOs, a method for dealing with deviations from the day-ahead energy market purchases must be considered comprehensively by each RTO or ISO within the framework of its overall market design.[157]

109. NEPOOL Participants states that the Commission should not impose its proposal on RTOs and ISOs before allowing NEPOOL Participants to evaluate, through its stakeholder process, issues around how deviation charges are calculated and assessed, including ISO New England's ability to separate out the types of deviation charges that the Commission has proposed.[158]

110. Constellation opposes this proposal, stating that eliminating

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[137] Energy Curtailment at 4–5; PG&E at 8.

[138] While APPA supports this proposal, it states that if bid and offer caps are eliminated during system emergencies, it cannot support uplifting such charges.APPA at 3.

[139] *E.g.*, Ohio PUC at 7–8; Public Interest Organizations at 6; EEI at 14–15; DRAM at 18–19.

[140] NIPSCO at 9; Old Dominion at 9.

[141] Dominion Resources at 8–9; ISO/RTO Council at 6–8.

[142] EEI at 14–15.

[143] TAPS at 9–11.

[144] Cogeneration Parties at 3.

[145] Midwest Energy at 3.

[146] NYISO at 7–8.

[147] *E.g.*, DRAM at 18–19; Comverge at 17–18; and NIPSCO at 12–14.

[148] NIPSCO at 12–14. The NERC reliability standard provides procedures that RTOs and ISOs must follow when capacity emergencies are declared and requires that all resources be used to meet load before operating reserves are tapped to address an emergency.

[149] Pennsylvania PUC at 11.

[150] *E.g.*, California PUC at 15–16; Industrial Consumers at 15–16 and Steel Manufacturers at 11–12.

[151] Duke suggests that a reasonable solution to preventing inequitable cost shifts is to establish a bandwidth that would determine whether deviation charges should apply. Duke at 5–7.

[152] NCPA states that the Commission's proposal to allow RTOs and ISOs to waive deviation charges should be expanded to include other contractual arrangements to the degree that ARCs are permitted to perform aggregations of retail load. NCPA at 5–6.

[153] OMS recommends that the Commission direct RTOs and ISOs to explore the development of programs that compensate market participants for demand reductions during system emergencies. OMS at 3.

[154] *Id.* at 3. Similarly, EEI asks the Commission to allow RTOs and ISOs to propose compensation sufficient to encourage demand response resources to incur the cost of reducing consumption. EEI at 14–15.

[155] ISO/RTO Council at 6–8.

[156] California Munis is not opposed to the Commission's proposal, but states that there are California-specific issues that must be considered, which may lead to a policy conclusion that elimination of deviation charge may not be appropriate for California. California Munis at 11–12.

[157] SoCal Edison-SDG&E state that eliminating charges in a uniform manner to all demand does not recognize the locational benefits of reducing demand in certain areas or cases where decreasing demand could hinder efforts to address grid reliability concerns. SoCal Edison-SDG&E at 3.

[158] NEPOOL Participants at 14.

deviation charges during system emergencies could create unintended consequences. Constellation believes that the proposal provides preferential treatment for energy providers that supply load reductions over generators that supply a similar product. Constellation argues that deviation charges are appropriate because such charges provide: (1) an incentive for LSEs to accurately forecast and bid their load into the day-ahead market; and (2) a source of funds to compensate out-of-market generators that are necessary to meet peak load when the real-time load deviates from its day-ahead load bid.[159] In addition, Constellation states that opportunities for the demand side of the market to respond are lost whenever supply resources are compensated outside of market-clearing prices through the use of uplift charges. It believes this problem can be alleviated through proper price formation.[160] For these reasons, Constellation recommends that the Commission leave the deviation charge in place and institute a shortage pricing regime, and address other issues that socialize out-of-market costs in order to minimize socialized uplift charges.[161]

ii. Commission Determination

111. The Commission adopts the NOPR proposal to require all RTOs and ISOs to modify their tariffs to eliminate a deviation charge to a buyer in the energy market for taking less electric energy in the real-time market than was scheduled in the day-ahead market during a real-time market period for which the RTO or ISO declares an operating reserve shortage or makes a generic request to reduce load in order to avoid an operating reserve shortage. This requirement does not apply to RTO or ISO wholesale demand response program participants, but rather to market buyers who voluntarily provide additional demand response either during or prior to an RTO- or ISO-directed operating reserve shortage in an effort to improve system reliability.

112. Removal of the deviation charge during a system emergency will eliminate a disincentive for participation of demand response in the real-time market. A buyer may be deterred from reducing demand during periods of reserve shortage if that buyer is subject to a charge for reducing its real-time consumption below its day-ahead purchases at the request of the RTO or ISO market operator. This unintended disincentive may result in the buyer maintaining a higher level of demand or discourage an LSE from calling on the demand response resources in its retail market. Removal of this disincentive will help maintain system reliability and help reduce prices during system emergencies.

113. Demand response program participants currently are not levied a deviation charge if they reduce demand as directed by the RTO or ISO, and the Commission's requirement in this Final Rule does not alter this practice. In addition, the Commission is not requiring that RTOs and ISOs remove penalties for day-ahead bidders of demand response that fail to follow dispatch instructions to reduce demand in real time. What this requirement does focus on is demand response that is provided by LSEs and other market buyers that consume less total energy in real time during system emergencies or at the request of the RTO or ISO than they had scheduled in the day-ahead market. The intent of the Commission's requirement is not only to ensure that market buyers who voluntarily reduce their energy consumption during system emergencies at the request of the RTO or ISO are not penalized for their deviation, but also that demand-side and supply-side resources are treated comparably.

114. As noted above, a majority of commenters support this requirement and agree that removal of these deviation charges would remove a disincentive for demand reduction. Elimination of deviation charges for a buyer's response to RTO and ISO calls for demand reductions also will further comparable treatment of demand and supply resources. RTO and ISO tariffs already do not impose deviation charges on generators that generate more power during system emergencies than scheduled in the day-ahead market.

115. An RTO or ISO must either propose amendments to its tariff to comply with this requirement or demonstrate in a compliance filing that its existing tariff and market design already satisfy this requirement. This compliance filing must be filed with the Commission within six months of the date that this Final Rule is published in the **Federal Register** . The Commission will assess each filing to determine if it satisfies the requirements of this section and will issue additional orders, as needed. This process addresses comments by RTO/ISO Council, California Munis, SoCalEdison-SDG&E, NEPOOL Participants and others recommending regional flexibility in addressing this issue.

116. The Commission encourages each RTO and ISO to work with its customers and other stakeholders in making tariff revisions and other changes to its market design necessary to comply with this requirement. The Commission's goal is to remove barriers to the development and use of demand response resources in wholesale energy markets, and the Commission expects that barriers can be effectively removed if each RTO and ISO works effectively and cooperatively with its customers and stakeholders.

117. Although the majority of commenters express support for this requirement, as noted above, a significant number ask for clarification or suggest changes to the NOPR proposal. Customer demand reduction in response to an emergency appeal benefits all customers, by averting or reducing the severity of a power shortage, so voluntary reductions during system emergencies can provide system-wide benefits. They can help maintain system reliability and reduce overall energy prices, which benefits all customers. As a result, the Commission finds that socialization of these costs is justified. However, in response to comments by NIPSCO and Old Dominion that the deviation charge should be allocated locally rather than on a system wide basis, this matter is best addressed in each RTO's or ISO's compliance filing. Any proposal for local allocation of these costs should be accompanied by an explanation of when costs would be spread across the entire RTO or ISO region and when applied locally, how the local area would be determined, and why local cost recovery is justified. Further, in response to comments by EEI and NIPSCO, we clarify that deviation charges would be eliminated only when the RTO or ISO announces an emergency situation or requests a voluntary load reduction after the close of the day-ahead market.

118. In response to TAPS's request for clarification on what forms of demand response this requirement would apply to, we note that this requirement applies to all buyers in the wholesale energy market, outside of an RTO's or ISO's demand response program, that may respond to an RTO or ISO request for voluntary load reduction during a system emergency. In response to comments by Cogeneration Parties and Midwest Energy state that the costs and benefits of load reduction must be verified before costs are imposed on customers, measurement and verification protocols should be addressed within the RTO's or ISO's compliance filing, and therefore will not require a net benefits test. In order to accommodate regional differences, we will also defer NYISO's request that the

[159] Constellation at 6.

[160] *Id.* at 7.

[161] *Id.* at 6–7.

Commission specify more clearly the definition of ''deviation charge'' to the compliance filing process (which will permit stakeholder input).

119. The Pennsylvania PUC asked for clarification of whether it is appropriate to eliminate deviation charges during periods of excess generation, when RTOs and ISO might call upon generators to reduce supply. The Commission notes that the intent of this Final Rule is to remove disincentives to demand-side resources so that they can be treated similarly and comparably in relation to supply-side resources. While it may be appropriate to remove deviation charges for supply-side resources during periods of excess generation, issues involving periods of excess generation are not addressed in this rulemaking.

120. We disagree with comments by the California PUC, Industrial Consumers and Steel Manufacturers recommending that deviation charges be eliminated any time demand deviates from schedule by using less energy. As noted in the NOPR, a reduction in demand during a system emergency benefits the RTO or ISO and its customers by better matching demand with available supply.[162] The Pennsylvania PUC mentions in its comments that if actual demand deviates from scheduled demand during non-emergency periods, such load reductions may result in periods of excess supply and impose costs on the RTO or ISO and its customers. Similarly, Duke's request that no deviation charges be assessed, so long as load remains within a specified bandwidth, may lead to greater disparity between day-ahead and real-time market purchases and could result in additional costs to consumers without providing consumer benefits. In particular, eliminating deviation charges for all periods could result in over-scheduling, which has cost consequences for generators. Therefore, the Commission does not accept these recommendations.

121. With regard to Constellation's recommendation that the Commission leave the deviation charge in place and institute a shortage pricing regime to better match supply and demand, the Commission is addressing shortage pricing issues in another part of this Final Rule. As noted above, we find that elimination of deviation charges for demand reduction during system emergency periods provides benefits to consumers distinct from those inherent in a shortage pricing regime and removes a disincentive to participation of demand-side resources by treating demand and supply comparably. The Commission therefore declines to adopt Constellation's recommendation.

b. Virtual Purchasers

122. In the NOPR, the Commission asked for comments on whether it should require RTOs and ISOs to modify their tariffs to eliminate deviation charges for virtual purchases during system emergencies.[163] The Commission noted that virtual purchasers may not cause significant additional costs during an emergency. Instead, virtual purchases may enhance reliability by increasing the amount of generation resources available in real time during a system emergency. Therefore, the Commission noted that assessing a deviation charge on virtual purchasers during an emergency may be unfair and may discourage helpful virtual purchases when system resources are expected to be tight.[164]

i. Comments

123. Several commenters state that virtual purchasers should be treated in the same manner as other ''physical'' purchasers by exempting their day-ahead market bids from deviation charges during system emergencies.[165] MADRI States and BP Energy assert that there is no need to assess deviation charges to virtual purchasers because such purchasers enhance reliability by increasing the amount of generation resources available in real-time during an emergency.[166] Mr. Borlick asserts that virtual bids in the day-ahead market do not impose any costs on the system; he states this is because an RTO and ISO is able to differentiate between virtual and physical bids and it can ignore the virtual bids when determining unit commitment for the next day's real-time operations.[167] Further, DC Energy claims that all buyers of energy (physical and virtual buyers) in the real-time market should be treated equally.[168]

124. Exelon agrees with the elimination of charges for virtual purchasers during system emergencies, but suggests that the Commission allow each RTO or ISO to implement such a rule after exploring the consequences of such action through its stakeholder process.[169]

125. Other commenters oppose this option and state that virtual purchasers should be subject to deviation charges.[170] For instance, First Energy and TAPS state that virtual purchasers provide no load reduction benefit and, therefore should not be exempt from paying the deviation charge. TAPS also states that the NOPR record contains no evidence that the hypothetical benefits of eliminating the deviation charge for virtual bidders would outweigh the harm that would result from removing deviation charges, as they act to discourage bidding behavior that imposes significant costs on consumers.[171] Several commenters believe that exempting virtual purchasers from deviation charges (1) may encourage speculation; (2) result in over commitment of generation when it is not needed; and (3) result in cost shifts to other market participants, thereby distorting markets.[172] APPA asserts that virtual bidders may be able to game the system and receive a payment when no benefit is provided to the region.

126. NEPOOL Participants believes that it is important to more fully evaluate the issues around virtual bidding and whether it is necessary to include virtual bidding in any discussion regarding the removal of deviation charges.[173]

ii. Commission Determination

127. The Commission agrees with the comments that virtual purchases can enhance reliability by increasing the amount of generation resources available in real-time during an emergency. Further, assessing a deviation charge on virtual purchasers during an emergency may be unfair and may discourage such virtual purchasing when it may be most beneficial to other customers. Our preferred policy is to eliminate deviation charges for virtual purchasers as well as physical purchasers during a real-time market period for which the RTO or ISO declares an operating reserve shortage or makes a generic request to reduce load in order to avoid an operating reserve

[162] NOPR, FERC Stats. & Regs. ¶ 32,628 at P 77.

[163] A virtual purchase (or sale) is a purchase (or sale) in the RTO or ISO day-ahead market that does not go to physical delivery. For example, an entity that does not serve load may make a purchase in the day-ahead market, which it must pay for, and then take no power in real time. This lack of consumption is treated as a sale of the purchased power into the real-time spot market. By making virtual energy purchases and sales in the day-ahead market and settling these positions in the real-time market, a market participant can arbitrage price differences between the two markets.

[164] NOPR, FERC Stats. & Regs. ¶ 32,628 at P 78.

[165] *E.g.,* Mr. Borlick at 2–3; BP Energy at 15; Exelon; MADRI States; and DC Energy at 5–6.

[166] MADRI States at 6–7; BP Energy at 15.

[167] Mr. Borlick at 3.

[168] BP Energy at 5.

[169] Exelon at 6–8.

[170] *E.g.,* Ameren at 24; APPA at 3; ISO New England at 9; ISO/RTO Council at 8; Old Dominion at 10; and TAPS at 10.

[171] First Energy at 8; TAPS at 9–11.

[172] ISO New England at 8–9; RTO/ISO Council at 6–8; and NYISO at 7–8.

[173] NEPOOL Participants at 13.

shortage. However, we are concerned an RTO's or ISO's particular market design may not readily accommodate this policy, and we acknowledge commenters' concerns about the possibility of market manipulation under a particular market design if deviation charges are removed for virtual purchasers. Therefore, we direct RTOs and ISOs to modify their tariffs to eliminate deviation charges for virtual purchasers, during the same period as they are eliminated for physical purchasers as set out above, unless the RTO or ISO upon compliance makes a showing that it would be appropriate to assess such deviation charges for virtual purchasers during this period. This approach establishes a reasoned generic policy and still provides an opportunity for each RTO or ISO, on a case-by-case basis, to present a factual record that the generic policy does not fit its overall market design.

4. Aggregation of Retail Customers

a. Commission Proposal

128. In the NOPR, the Commission proposed to require RTOs and ISOs to amend their market rules as necessary to permit an ARC to bid demand response on behalf of retail customers directly into the RTO's or ISO's organized markets, unless the laws or regulations of the relevant electric retail regulatory authority do not permit a retail customer to participate.[174]

129. The Commission recognized that each region's market design is different and that it is important for ARC provisions to respect these market design differences. For this reason, the Commission proposed not to mandate generic market rule amendments; rather, it proposed to require RTOs and ISOs to amend their tariffs and market rules as necessary to allow an ARC to bid demand response directly into the RTO's or ISO's organized market, provided that the ARC's demand response bid must meet the same requirements as a demand response bid from any other entity such as an LSE. The NOPR proposed the following flexibilities in RTO and ISO market designs:

- The RTO or ISO may require the ARC to be an RTO member if membership is a requirement for other bidders.
- RTOs and ISOs may require that an aggregated bid must consist of individual demand response bids from a single area, reasonably defined.
- An RTO or ISO may place appropriate restrictions on any customer's participation in an ARC-aggregated demand response bid to avoid counting the same demand response resource more than once.
- The market rules do not have to allow bids from an ARC if this is not permitted under the laws or regulations of the relevant electric retail regulatory authority. The RTO or ISO must receive explicit notification from the relevant retail regulatory authority in order to disqualify a bid from an ARC that includes the demand response of that authority's retail customers.

130. The Commission requested comment about whether: (1) These features of the proposal are appropriate and whether there are additional appropriate criteria or features for allowing an ARC to bid demand response; and (2) there is any reason not to subject an ARC to the same requirements as any other bidder in the energy market.[175]

131. The Commission proposed that an RTO or ISO must either propose amendments to its tariff to comply with the requirement or demonstrate in a filing that its existing tariff and market design already satisfy the requirement to permit an ARC to bid demand response on behalf of retail customers.[176] It also proposed that this filing be submitted within six months of the date the Final Rule is published in the **Federal Register**. The Commission proposed that it would assess whether each filing satisfies the proposed requirement and would issue additional orders as necessary.

b. Comments

i. Comments regarding ARC proposal

132. Many commenters support the NOPR proposal to allow ARCs to bid demand response directly into organized markets, unless it is not permitted by the relevant regulatory authority.[177] For instance, EEI asserts that the Commission should adopt this proposal in the Final Rule because it is appropriate for RTOs and ISOs to treat ARCs comparably to wholesale market participants under RTO and ISO rules as long as: (1) State commissions permit aggregation of retail demand response; (2) such treatment is aligned with state requirements; and (3) no preferential treatment is accorded to ARCs, including being subject to monitoring and verification requirements.[178] Some commenters note that experiences in organized markets have demonstrated that allowing ARCs to participate directly in wholesale energy markets has increased market efficiency and led to greater diversity of demand response options.[179] In particular, Comverge and EnerNOC note that allowing ARCs to enter wholesale energy markets has been successful in PJM, ISO New England, and NYISO.[180]

133. Industrial Coalitions note that this proposal would expand the pool of potential demand response providers, thereby increasing demand elasticity. American Forest states that the proposal could encourage development of state-level retail programs that may not otherwise be considered. The potential for such participation may encourage the development of state law or retail structures to accommodate participation where none now exists as retail customers seek to avail themselves of the opportunities larger markets offer.[181]

134. Ameren states, however, that unless RTOs and ISOs develop and properly implement clear tariff provisions and market rules that explain how the aggregation of retail customers for demand response reductions will work, LSEs and providers of last resort could be harmed by ARCs' demand bids. Ameren asserts that ARCs' unanticipated demand reductions can expose LSEs and providers of last resort to the difference between day-ahead and real-time locational marginal prices, as well as to deviation charges due to this difference. Ameren urges the Commission to require RTOs and ISOs to adopt tariff provisions and market rules that protect LSEs and providers of last resort from such harm if an ARC reduces load. Similarly, NCPA urges the Commission to require coordination among the LSE, the ARC, and the RTO or ISO. NCPA asserts that such coordination is necessary to preserve the value of the demand response and to prevent imprudent resource planning or operating decisions.[182]

135. BP Energy is concerned that ARCs' participation in wholesale markets during non-emergency periods can lead to gaming. Therefore, it recommends that the Commission consider restricting or eliminating during any non-emergency period any

[174] NOPR, FERC Stats. & Regs. ¶ 32,628 at P 86.

[175] *Id.* P 88, 91.

[176] *Id.* P 92.

[177] *E.g.,* American Forest; BlueStar Energy; BP Energy; California PUC; Comverge; DC Energy; Dominion Resources; DRAM; EEI; EnergyConnect; Energy Curtailment; EnerNOC; Exelon; FirstEnergy; IMEA; Industrial Coalitions; Industrial Consumers; Integrys Energy; ISO/RTO Council; LPPC; MADRI States; Midwest ISO; NYISO; Ohio PUC; OMS; OPSI; Pennsylvania PUC; PG&E; Public Interest Organizations; Reliant; Retail Energy; Steel Producers; Wal-Mart; and Xcel.

[178] EEI at 16.

[179] *E.g.,* DRAM at 20; EnerNOC at 12.

[180] Comverge at 18; EnerNOC at 12–13.

[181] American Forest at 5–6.

[182] NCPA at 3–4.

incentive, subsidy or capacity-type payment for RTO and ISO demand response programs related to energy markets.[183] Similarly, LPPC states that each RTO or ISO should adopt mechanisms to prevent gaming of the program.[184]

136. TAPS believes that the Commission's proposal regarding ARCs may require existing LSE demand response programs to change to accommodate the ARC demand response programs, which would increase rather than decrease barriers to effective demand response programs. It requests clarification that the Commission's proposal would not require any change to an existing aggregation program that already functions well.

137. Several regional entities maintain that they are already working to allow ARC participation in their markets. CAISO states that it is working with its stakeholders and California PUC to address regulatory policy and state law concerning aggregation. ISO New England states that its current market rules allow ARCs to aggregate retail customers for the purpose of participating in demand response programs and the forward capacity market. Midwest ISO notes that, in accordance with the Commission's ASM Order,[185] it will continue to work with stakeholders to develop tariff provisions to allow ARCs to operate within its footprint. Finally, NYISO states that it is making efforts to identify common issues and best practices related to demand resource bidding programs.[186]

138. SPP states that there are no states within its footprint that currently provide retail access. However, to the extent there would be an ARC within its footprint, it notes that it would be up to the relevant retail regulatory authority to determine whether retail load would be permitted to participate in the wholesale market demand response program.[187]

ii. Comments on regulatory approval of ARCs

139. Most regulatory authorities, including NARUC, as well as other commenters, such as NRECA, APPA, and TAPS, ask the Commission to modify its proposal to clarify that an ARC or any retail customer may not bid load-reduction response into an RTO or ISO market without the relevant retail regulatory authority's express permission.[188] They assert that the Commission's proposal would allow ARCs to bid retail demand response into organized energy markets without express permission from the relevant retail regulatory authority and thereby place a burden on the local authority to take affirmative action to disallow such participation. Some assert that such a burden displaces state authority and would impose an undue burden on municipalities, resulting in unintended consequences.[189] They state that an ARC's participation should be subject to the rules and laws of the relevant retail regulatory authority and argue that an ARC or any retail customer should not bid load-reduction response into an RTO or ISO market without the relevant retail regulatory authority's express permission. They contend that the burden should be on the ARC or the regional entity to obtain state regulators' permission for the demand response program, and not on the retail electric regulatory authority to prohibit it.

140. The Final Rule, they contend, should specify that an RTO or ISO can accept ARC bids only if the relevant electric retail regulatory authority affirmatively informs the RTO or ISO that it permits ARC activities for its retail load; without such explicit notification, the RTO should presume that an ARC could not lawfully aggregate the retail load. For instance NARUC states that the last criterion proposed by the Commission should be revised to state that:

> The market rules shall not allow bids from an ARC unless this is expressly permitted under the laws or regulations of the relevant electric retail regulatory authority. The RTO or ISO must receive explicit notification from the relevant retail regulatory authority in order to qualify a bid from an ARC that includes the demand response of that authority's retail customers.[190]

141. NRECA argues that if the Commission does not require explicit permission from the relevant authority, ARCs would effectively be allowed to cherry-pick the best load response resources out of existing LSE demand response programs. NRECA contends that this would deprive those LSEs of important resources used to keep rates down for all consumers.[191] APPA, like NRECA, asks that the Commission require RTOs and ISOs to assume that in the case of public power systems, aggregation is not permitted unless the state's retail regulatory authority has notified the RTO or ISO otherwise. However, if the Commission maintains the NOPR proposal over APPA's objections, APPA suggests an alternative approach to this issue, making it clear that this is not its preferred approach. It suggests that the Commission implement its proposal for power systems with 4 million MWh or more in total annual output, but exempt systems of smaller size.[192] That is, for power systems above 4 million MWh of total annual output the presumption would be as proposed by the Commission: that an ARC or individual retail consumer may bid demand response into an organized wholesale power market unless the relevant electric retail regulatory authority notifies the RTO or ISO that this is not permitted. For smaller systems, the presumption would be that retail load may not be bid into the organized market, unless the relevant electric retail regulatory authority expressly indicates that participation by retail customers is permitted. APPA states that this option would preserve the Commission's intention to remove barriers to the participation of demand response resources in organized wholesale electricity markets while not imposing an undue burden on small systems that may not be prepared to address this issue.

142. E.ON U.S. opposes the proposal on the grounds that it violates the separation of federal and state jurisdiction and places at risk a utility's obligation to serve its retail load.[193] It notes that state regulatory commission approval is required before retail customers may band together to offer a bid into the wholesale market and such an approval will be difficult if the program benefits large customers to the detriment of many small customers. Also, while Mr. Borlick does not oppose the proposal, he states that ARCs are not the best means for promoting demand response resources.[194]

143. PG&E asserts that explicit approval of the regulatory authority is

[183] BP Energy at 16.

[184] LPPC at 8.

[185] *See infra* note 60.

[186] NYISO at 10.

[187] SPP at 5–6.

[188] *E.g.,* APPA at 43; California PUC at 17; IMEA at 2; Kansas CC at 2; Maine PUC at 4; NARUC at 8; NCPA at 3; North Carolina Electric Membership at 5; NRECA at 12; Ohio PUC at 8; Pennsylvania PUC at 12; NIPSCO at 13; PG&E at 9; and Old Dominion at 13.

[189] *E.g.,* NRECA at 10–14; NARUC at 7; TAPS at 13; and IMEA at 2. APPA notes that only a small fraction of the 1,315 public systems providing retail electric services in states served by RTOs and ISOs have laws or rules that address end-use aggregation. Therefore, it argues that requiring relevant electric retail regulatory authority to take affirmative actions to consider retail aggregation by ARCs can be a substantive undertaking. APPA at 44.

[190] NARUC at 9. PG&E and NRECA offer similar revisions. PG&E at 10; NRECA at 11.

[191] NRECA at 14.

[192] APPA at 47. APPA states that the United States Small Business Administration defines an entity whose total annual output is under 4 million MWh as a small utility. APPA at 45 & n.21.

[193] E.ON U.S. at 11.

[194] Mr. Borlick at 3.

needed to assure that opportunities for unreasonable and unfair allocations of cost are eliminated and that critical enabling elements have been established. According to PG&E, this includes: (1) Assuring that a customer properly informs a load-serving entity of its demand response participation; (2) assurance that costs are not inappropriately transferred from one group of customers to another through demand response aggregation; (3) that appropriate RTO or ISO metering protocols exist to eliminate double counting concerns; and (4) resource adequacy value is fairly allocated.[195]

144. Wal-Mart, however, states that the Commission has the authority to promote aggregation of retail load reduction bids, including bids from individual retail customers, and should not require RTOs or ISOs to reject bids unless permitted by the relevant retail regulatory authority.[196] Similarly, some commenters assert that the Commission should exercise its jurisdiction over demand response programs to direct RTOs and ISOs to allow any retail customer either on its own or through an aggregator to participate in RTO or ISO demand response programs as long as the customer can meet the operational requirements of the RTO or ISO tariff, without consulting with a state commission.[197] They contend that such unrestricted access to demand response programs is the best way to maximize program participation and thereby bring benefits to organized markets. In the alternative, however, they state that they support the NOPR proposal.[198]

145. Xcel supports the proposed rule on aggregation by ARCs, but asks the Commission to clarify how the RTO or ISO would receive explicit notification from the relevant regulatory authority to disqualify an offer from an ARC. Xcel suggests that the Commission follow the procedure used for compliance with NERC mandatory electric reliability standards and require each ARC to register with the RTO or ISO, which could then require the ARC to certify that it has received the appropriate regulatory approval.[199]

iii. Comments on proposed criteria and regional flexibility

146. Many commenters state that they support the Commission's proposed criteria and regional flexibility for RTOs and ISOs listed in the NOPR for allowing an ARC to bid retail load-response into an RTO or ISO market.[200] For example, LPPC believes that the proposed criteria are useful in evaluating RTO and ISO implementation of the proposal. It also suggests two additional criteria: (1) the RTO or ISO must demonstrate that its procedure for administering ARC bids effectively coordinates activities of the ARCs and LSEs; and (2) the Commission should ensure that there is a demonstration of net benefits to consumers and that a system is in place for verifying that demonstrated load reduction is achieved.[201]

147. Reliant agrees with the Commission's proposed criteria, but it believes that the most effective approach for demand response development is through the direct relationship between the retail customer and its LSE.[202]

148. Many commenters support the NOPR proposal to allow each market to develop its own rules to implement retail aggregation by ARCs.[203] For example, Dominion Resources agrees with the Commission that it is important for RTOs and ISOs to have flexibility in developing ARC provisions to account for regional differences.[204] EEI stresses that RTOs and ISOs should have flexibility to adopt pricing methods and other provisions that reflect regional differences.[205] NEPOOL Participants states that the current arrangements in ISO New England already allow ARCs to participate in its markets, and any changes to the existing program to accommodate Commission directives should be handled through the stakeholder process. SoCal Edison-SDG&E believe that CAISO should have the flexibility to pursue development of demand response programs without being constrained by overly broad nationwide restrictions and requirements. California Munis urges the Commission to consider regional and jurisdictional distinctions that may affect ARCs' effectiveness, noting that some states and local jurisdictions within RTO or ISO may not have adopted a retail choice model.

149. Public Interest Organizations, however, recommend that the Commission adopt a more detailed generic (*pro forma*) set of market rules on ARCs, which RTOs and ISOs may modify based on regional differences if the modifications are comparable or superior to the Commission's rules. According to Public Interest Organizations, these *pro forma* rules could be developed through a technical conference.

iv. Comments on Specific ARC Requirements and Clarifications

150. Many commenters assert that it is important that ARCs be required to comply with necessary technical requirements.[206] For instance, several commenters state that certain technical matters should be standardized, including (1) the method for determining baseline compensation, (2) tools to establish uniform baselines and verification, (3) interface tools for demand response to use a common portal and protocol in organized markets, and (4) telemetry and metering requirements.[207] DC Energy states that ARCs should provide verification of measurement equal to others in the same market and notes that all participants should have similar requirements for the ability to bid into wholesale markets. DRAM and Converge state that double payment should be avoided and FirstEnergy asserts that each RTO or ISO should adopt appropriate restrictions to avoid double counting.

151. EnergyConnect notes that past efforts to aggregate small retail loads have not been successful primarily due to the requirement that every small resource in an aggregated group meet the same registration, measurement and verification standards as large generators or other resources. EnergyConnect recommends the use of sampling or other techniques to address this issue.

152. Several commenters seek clarification of various aspects of the proposal. For instance, EEI stresses that the Final Rule should clarify that RTOs and ISOs may specify certain requirements of ARCs, such as registration and creditworthiness requirements, and that RTOs and ISOs should have the flexibility to adopt pricing methods and other provisions that reflect regional differences.[208] Industrial Coalitions also ask the Commission to clarify that ARCs, like LSEs and industrial customers, should be held accountable for responding

[195] PG&E at 9.

[196] Wal-Mart at 6–7.

[197] Integrys Energy at 4–5; Retail Energy at 2.

[198] Integrys Energy at 5; Retail Energy at 2

[199] Xcel at 9–10.

[200] *E.g.,* Exelon at 9; Industrial Consumers at 16; LPPC at 8; MADRI States at 5;NYISO at 9; Reliant at 6; and Wal-Mart at 7.

[201] LPPC at 8.

[202] Reliant at 6.

[203] *E.g.,* APPA; California Munis; Dominion Resources; EEI; Exelon; ISO/RTO Council; Old Dominion; NEPOOL Participants; and SoCal Edison-SDG&E.

[204] Dominion Resources at 5.

[205] EEI at 17.

[206] *E.g.,* NYISO at 5; LPPC at 7; Comverge at 18; EEI at 2; and Industrial Consumersat 14.

[207] *E.g.,* DRAM at 21; Comverge at 18; and NEPOOL Participants at 9.

[208] EEI at 17.

when called upon by their respective RTO or ISO. LPPC requests that the Commission clarify that its rules would not permit ARC bids to be submitted on behalf of load served by LSEs that are not RTO or ISO members. Similarly, SMUD requests clarification that the Commission did not intend that loads located outside the control area of an RTO or ISO would participate in demand response programs, whether through a retail aggregator or directly with the RTO or ISO.

153. NYISO states that the Commission should not accept proposals that would provide preferential treatment to ARCs or that would not be comparable to the rules for other demand resources or generators.[209] NYISO suggests that the Commission amend its proposed regulatory text in section 35.28(g)(iii) to clarify that ARCs must meet ''applicable reliability requirements'' before they can bid into regional markets, and clarify that the reference to ''organized market'' has the same meaning as proposed under subsection (g)(i).[210] Similarly, it states that the Commission should conform subsection (g)(iii) to (g)(i) so that (g)(iii) will specifically require ARCs to comply with ''necessary technical requirements under the RTO or ISO tariff.'' NYISO notes that such a change will ensure that RTOs and ISOs may adopt reasonable metering, verification, communications, minimum size, and other technical rules for both individual demand resources and ARCs.[211]

c. Commission Determination

154. The Commission adopts in this Final Rule the proposed rule to require RTOs and ISOs to amend their market rules as necessary to permit an ARC to bid demand response on behalf of retail customers directly into the RTO's or ISO's organized markets, unless the laws or regulations of the relevant electric retail regulatory authority do not permit a retail customer to participate. We find that allowing an ARC to act as an intermediary for many small retail loads that cannot individually participate in the organized market would reduce a barrier to demand response. Aggregating small retail customers into larger pools of resources expands the amount of resources available to the market, increases competition, helps reduce prices to consumers and enhances reliability. We also agree with commenters that this proposal could encourage development of demand response programs and thereby provide retail customers more opportunities available through larger markets. Additionally, as some commenters note, experiences with existing aggregation programs in PJM, NYISO, and ISO New England have shown that these programs have increased demand responsiveness in these regions.

155. We are mindful of the comments that allowing ARCs to bid into the wholesale energy market without the relevant electric retail regulatory authority's express permission may have unintended consequences, such as placing an undue burden on the relevant electric retail regulatory authority. In the NOPR, the Commission sought to address the concerns of state and local retail regulatory entities by proposing to require that an ARC may bid retail load reduction into an RTO or ISO regional market unless the laws or regulations of the relevant electric retail regulatory authority do not permit a retail customer to participate in this activity. The Commission's intent was not to interfere with the operation of successful demand response programs, place an undue burden on state and local retail regulatory entities, or to raise new concerns regarding federal and state jurisdiction, as some commenters argue. As described above, we clarify that we will not require a retail electric regulatory authority to make any showing or take any action in compliance with this rule. Rather, this rule requires an RTO or ISO to accept a bid from an ARC, unless the laws or regulations of the relevant electric retail regulatory authority do not permit the customers aggregated in the bid to participate.

156. In response to E.ON U.S., we do not agree that the approach we adopt here violates the separation of federal and state jurisdiction. Rather, we find that this action properly balances the Commission's goal of removing barriers to development of demand response resources in the organized markets that we regulate with the interests and concerns of state and local regulatory authorities.

157. With regard to LPPC's request that ARCs not bid on behalf of load served by LSEs that are not RTO or ISO members, SMUD's request for clarification that loads outside of an RTO's or ISO's control area would not participate in demand response programs, and TAPS's comment that the proposal should not require a change to an existing retail load reduction program, the continuing role of the relevant retail electric regulatory authority adequately addresses these concerns.

158. Further, we agree with the comments that, because each region's market design is different, it is important to permit each RTO or ISO to design ARC provisions that account for these differences. Therefore, instead of developing pro forma language or requiring RTOs and ISOs to make detailed generic market rule amendments, we direct RTOs and ISOs to amend their tariffs and market rules as necessary to allow an ARC to bid demand response directly into the RTO's or ISO's organized market in accordance with the following criteria and flexibilities that remain largely unchanged from those advanced in the NOPR:

a. The ARC's demand response bid must meet the same requirements as a demand response bid from any other entity, such as an LSE. For example:

i. Its aggregate demand response must be as verifiable as that of an eligible LSE or large industrial customer's demand response that is bid directly into the market;

ii. The requirements for measurement and verification of aggregated demand response should be comparable to the requirements for other providers of demand response resources, regarding such matters as transparency, ability to be documented, and ensuring compliance;

iii. Demand response bids from an ARC must not be treated differently than the demand response bids of an LSE or large industrial customer.

b. The bidder has only an opportunity to bid demand response in the organized market and does not have a guarantee that its bid will be selected.

c. The term ''relevant electric retail regulatory authority'' means the entity that establishes the retail electric prices and any retail competition policies for customers, such as the city council for a municipal utility, the governing board of a cooperative utility, or the state public utility commission.

d. An ARC can bid demand response either on behalf of only one retail customer or multiple retail customers.

e. Except for circumstances where the laws and regulations of the relevant retail regulatory authority do not permit a retail customer to participate, there is no prohibition on who may be an ARC.

f. An individual customer may serve as an ARC on behalf of itself and others.

g. The RTO or ISO may specify certain requirements, such as registration with the RTO or ISO, creditworthiness requirements, and certification that participation is not precluded by the

[209] NYISO at 9–10.

[210] Section 35.28 (g)(i) establishes that ''organized markets'' includes any RTO or ISO-administered market based on competitive bidding.

[211] NYISO at 10.

relevant electric retail regulatory authority.[212]

h. The RTO or ISO may require the ARC to be an RTO or ISO member if its membership is a requirement for other bidders.

i. Single aggregated bids consisting of individual demand response from a single area, reasonably defined, may be required by RTOs and ISOs.

j. An RTO or ISO may place appropriate restrictions on any customer's participation in an ARC-aggregated demand response bid to avoid counting the same demand response resource more than once.

k. The market rules shall allow bids from an ARC unless this is not permitted under the laws or regulations of relevant electric retail regulatory authority.

159. The above criteria in combination with regional flexibility will provide the foundation for each RTO and ISO to work with its stakeholders, including state and local regulatory entities, to develop market rules that will enable more small entities to provide demand response to the regional markets. Such a process would provide the forum necessary to discuss and resolve concerns raised by the commenters in this proceeding, including: (1) Developing standardized terms and conditions, (2) the requirement that ARC's demand response bid must meet the same requirements as other demand response bids,[213] (3) verification and measurement, (4) penalties for non-compliance, (5) registration and creditworthiness requirements, and (6) mechanisms to prevent gaming. Further, in response to those who ask us to require in this rule (1) that each RTO or ISO should be required to demonstrate net benefits of its program, (2) that bids should be aggregated on a local basis, and (3) that so called ''double payment'' should be either required or prohibited, we decline to do so here. Such issues are more appropriately addressed by each region in its compliance filing if it chooses to do so.

160. Given this regional approach, we do not find that standardized technical issues or a *pro forma* set of market rules, as raised by some commenters, is necessary at this time. The comments do not persuade us to add additional criteria to the criteria adopted herein. As noted above, we encourage RTOs and ISOs to coordinate their efforts with customers, state and local regulatory entities, and other stakeholders. The Commission will consider such regional proposals in the compliance filings. Further, we agree with commenters on the need for coordination of the activities of the ARCs and LSEs to ensure efficient operation of the markets.

161. In accordance with NYISO's recommendation, the Commission will clarify that its regulatory reference in § 35.28 (g)(ii) to ''organized market'' has the same meaning as proposed under (g)(i) and that ARCs are to comply with any necessary technical requirements under the RTO's or ISO's tariff.

162. Regarding NYISO's recommendation that the Commission clarify that ARCs must meet ''applicable reliability requirements,'' the Commission does not see a need to change its proposed language in this rulemaking because reliability issues are addressed by each RTO or ISO in accordance with Commission established reliability requirements.

163. Each RTO and ISO is required to submit, within six months of the date that this Final Rule is published in the **Federal Register**, a compliance filing with the Commission, proposing amendments to its tariffs or otherwise demonstrating how its existing tariff and market design is in compliance with the requirements of this Final Rule.

164. We appreciate comments of CAISO, ISO New England, Midwest ISO, and NYISO that they are already working with stakeholders to allow ARCs to operate within their footprint or to address compliance issues. With regard to SPP's comment that there is no retail access state within SPP, the Commission notes that its ARC requirements are not limited to aggregation of retail customers who have retail choice. We will not prejudge here whether any nascent ARC program will satisfy our requirements. Nor will we decide whether a regulator of a traditional, vertically-integrated monopoly utility may give permission for an ARC to aggregate retail customers' demand responses for bidding into SPP's markets. SPP may explain in its compliance filing its situation regarding retail choice but should also explain how it would accommodate a bid from an ARC consistent with the criteria listed above.

5. Market Rules Governing Price Formation During Periods of Operating Reserve Shortage

165. In the NOPR, the Commission observed that existing RTO and ISO market rules continue to appear to be unjust, unreasonable, and unduly discriminatory or preferential during periods of operating reserve shortages. In particular, the Commission noted that these rules may not produce prices that accurately reflect the true value of energy in such an emergency and, by failing to do so, may harm reliability, inhibit demand response, deter new entry of demand response and generation resources, and thwart innovation.[214]

166. Therefore, the Commission proposed to reform market rules governing price formation in RTO and ISO energy markets during operating reserve shortages. Specifically, the Commission proposed to require each RTO or ISO with an organized energy market to make a compliance filing, within six months of the date that the Final Rule is published in the **Federal Register**, proposing any necessary reforms to ensure that the market price for energy accurately reflects the value of such energy during shortage periods (*i.e.*, an operating reserve shortage). The Commission stated that each RTO or ISO may propose one of four suggested approaches to pricing reform during an operating reserve shortage or to develop its own alternative approach to achieve the same objectives. These approaches are discussed in section (b) of this chapter. Alternatively, an RTO or ISO may demonstrate that its existing market rules already reflect the value of energy during periods of shortage and, therefore, do not need to be reformed. The Commission proposed to require RTOs and ISOs proposing reforms or demonstrating the adequacy of existing market rules to provide an adequate factual record for the Commission to evaluate their proposals; and proposed six criteria by which the Commission would evaluate the RTO's or ISO's compliance filing. The Commission asked for comments on these criteria. The Commission noted that any change in market rules to implement the proposed reforms must consider the issue of market power abuse, recognize regional differences in market rules, and be based on a sound factual record.

167. Further, the Commission stated that it would require any RTO or ISO proposing reform in this area to address the adequacy of any market power mitigation measures that would be in place during periods of operating reserve shortage. In addition, to ensure an adequate record on the issue of market power mitigation, the Commission proposed to solicit the views of the Independent Market

[212] The RTO or ISO should not be in the position of interpreting the laws or regulations of a relevant electric retail regulatory authority.

[213] We note that ''same requirement'' does not necessarily mean identical to other demand response bids. An ARC's demand response bid must meet similar or comparable requirements as other demand response bids.

[214] NOPR, FERC Stats. & Regs. ¶ 62,628 at P 107.

Monitor for each RTO or ISO region on any proposed reforms in this area.

168. Section (a) of this Chapter presents a discussion of the Commission's proposed rule to reform pricing for RTOs and ISOs to more accurately reflect the value of energy during periods of operating reserve shortage. Section (b) addresses comments on the four approaches provided by the Commission that RTOs and ISOs must consider in addressing this issue. Section (c) addresses the six criteria that the Commission proposed to ensure that any reforms implemented by an RTO or ISO achieve the desired results; and section (d) addresses the option for each RTO or ISO to phase-in its reform proposal over a number of years.

a. Price Formation During Periods of Operating Reserve Shortage

i. Comments

169. A number of commenters state that they support the proposed rule on price formation during periods of operating reserve shortage.[215] Some of these commenters assert that prices must be allowed to reflect the true value of energy during an operating reserve shortage in order for wholesale energy markets to operate efficiently.[216] Other commenters state that a transparent price signal can: (1) Enhance system reliability and protect customers; [217] (2) encourage a vibrant demand response market because both demand response and other sources of energy supply will participate in the market to a greater degree; [218] and (3) encourage those with advanced metering technology to follow energy prices more closely, and those without such technology to acquire it.[219]

170. EEI maintains that RTOs and ISOs should modify their market rules to allow the market-clearing price to accurately reflect the value of energy during periods of operating reserve shortages. It also agrees that any change in market rules must consider the issue of market power, recognize regional differences in market rules, and be based on a sound factual record.[220]

171. PJM Power Providers asserts that accurate price signals are the cornerstone of a successful wholesale market design. It notes that many of the problems in wholesale electric markets stem from market design features that suppress prices during shortage conditions to levels below the value of lost load.[221] It adds that shortage pricing can provide short-term signals to generation to ensure production and long-term signals to allow for fixed cost recovery supporting maintenance of existing facilities and new entry. Therefore, PJM Power Providers asserts that a shortage pricing mechanism must be integrated with the overall market design.

172. Reliant states that for all RTOs and ISOs—with or without capacity markets, prices in real-time should properly signal needed responses from both supply-side and demand-side resources. To the extent that price caps or bid mitigation suppress the appropriate price signals in the energy market, reforms should be made. These price signals are needed to encourage the necessary short-term response to the market and also to provide critical pricing information to the market.[222] Reliant argues that the current market design in several RTOs and ISOs does not support the investment needed to maintain system reliability.[223] It asserts that transparent price signals in the market will encourage the most efficient and effective implementation of new generation and demand-side technology and investment. Therefore, to the extent that RTO and ISO market design fails to provide such transparent price signals, Reliant asserts that the Commission should direct necessary pricing reforms.[224]

173. Several commenters note that they support the proposed shortage pricing proposal and also note that generation and demand resources should be treated comparably during shortage pricing.[225] For instance, OMS states that both generation and demand resources are equally valuable so they should be treated comparably. In that respect, it notes that, similar to generators, demand resources, if offered and accepted into the market during shortage periods, should be assessed penalties if the RTO calls on them and they do not comply.[226]

174. Several commenters support the Commission's proposal to recognize regional differences by adopting a flexible regional approach, rather than a general mandate.[227] These commenters state that given the market design and rule variations among organized markets, a one-size-fits-all approach may not be appropriate. They believe that it is reasonable for the Commission to establish fundamental principles and necessary elements for promoting demand responsiveness, while leaving the specifics of implementation to each RTO or ISO market. Therefore, they support the Commission's proposal to allow each region to choose its own shortage pricing approach from the four offered or to choose another developed through the stakeholder process.

175. EEI also strongly supports the Commission's regional approach; stating that, given the regional differences in market design, each region should have the flexibility to propose its own approach or demonstrate that its existing market rules satisfy this requirement.[228] Similarly, California PUC states that implementation of this rule should be done through collaborative efforts between the state commission and its respective RTO or ISO (*e.g.*, how the shortage price is set, at what level it is set, and under what circumstances the shortage price is triggered).[229]

176. Several regional entities assert that they are in compliance or will be in compliance with the proposed rule. For instance, CAISO states that it will be in compliance with the proposed plans to incorporate a demand curve for reserves within 12 months of the roll-out of MRTU, as directed by the Commission.[230] Midwest ISO states that it is in compliance with the proposed rule because its recently-approved ancillary services market incorporates a demand curve for operating reserves.[231] NYISO maintains that it intends to demonstrate in its compliance filing that

[215] *E.g.*, Mr. Borlick; BP Energy; CAISO; California PUC; Comverge; Constellation; DC Energy; Dominion Resources; DRAM; Duke Energy; EEI; EPSA; Exelon; FirstEnergy; Integrys Energy; Ohio PUC; OMS; Potomac Economics; PJM Power Providers; PPL Parties; and Reliant.

[216] *E.g.*, BP Energy at 22; Mr. Borlick at 5; Comverge at 20, 22; Dominion Resources at 7; Exelon at 11; OMS at 6; PPL Parties at 5; and PJM Power Providers at 3.

[217] Comverge at 20, 23; PPL Parties at 5. PPL Parties notes that "customers will be protected because the price signal will encourage more robust bilateral contracting, self-supplied generation, the improved use of hedging and financial instruments, and increased amounts of demand responsive load." PPL Parties at 6.

[218] PPL Parties at 5.

[219] OMS at 6.

[220] EEI at 19.

[221] PJM Power Providers at 3. *See also* PPL Parties at 5 ("implementing appropriate [shortage] pricing will require permitting energy prices to rise when warranted to reflect the average value of lost load").

[222] Reliant at 8.

[223] For example, in Midwest ISO and CAISO, Reliant notes that market revenues were not sufficient to support new generation investment. *Id.* at 9.

[224] *Id.* 9–10.

[225] PPL Parties at 5; First Energy at 11; and OMS at 6.

[226] OMS at 6.

[227] *E.g.*, CAISO; EEI; EPSA; ISO/RTO Council; Midwest ISO; PJM Power Providers; Old Dominion; Wal-Mart; ISO New England; NYISO; NY TOs; Detroit Edison; Dominion Resources; and SPP.

[228] EEI at 19.

[229] California PUC at 19. CAISO also states that it supports the Commission's proposal to require RTOs and ISOs to study shortage pricing market reforms and report back to the Commission.

[230] CAISO at 3.

[231] Midwest ISO at 16.

its rules fully satisfy the NOPR's requirements.[232] ISO New England also states that it has a demand curve for operating reserves and thus is in compliance with the proposal.[233]

177. Many commenters object to the Commission's proposed rule on pricing reform during periods of operating reserve shortages, and they proffer various reasons.[234] Some of these commenters oppose the proposed rule on grounds that it will result in exercise of market power because the organized markets are not competitive,[235] leading to unjust and unreasonable rates. APPA argues that the prices produced by RTO or ISO markets do not reflect the actual economic costs of providing service because the rates are not the product of competitive markets.[236] According to APPA, the only restraint on generation suppliers' ability to extract the maximum amount of profits from regional markets is the RTO's and ISO's market mitigation rules. It states that exposing retail consumers directly to unmitigated price signals would result in unjust and unreasonable rates. Therefore, APPA urges the Commission to first address market deficiencies, including market competitiveness and proper demand response infrastructure, in order to enable consumers to respond to higher prices.[237] NRECA argues that the Commission would violate its duty under FPA if it were to subject customers to unjust and unreasonable rates, even if those excessive rates were limited to emergency situations.[238]

178. LPPC is opposed to proposals that would permit generation prices to rise above rate cap levels during scarcity situations.[239] According to LPPC, the proposed rule would undermine the Commission's core mission to ensure just and reasonable rates and would result in an unjust and unreasonable transfer of wealth from customers to generators. It notes that the Commission has long approved the use of price caps in RTO and ISO markets in order to mitigate market power and to protect customers from unreasonable prices during periods of capacity deficiency or emergency.[240] It asserts that removing these price caps would be inconsistent with Commission precedent that market-based rates may be relied on only where the Commission has determined that the market is sufficiently competitive.[241] It further argues that the Commission is abdicating market mitigation by abandoning price caps when it has previously determined that price caps are needed to restrain prices in times of scarcity.[242] Therefore, instead of removing bid caps, LPPC believes that the Commission should promote demand response through payments for demand reduction.

179. Several commenters dispute the Commission's premise that customers will be able to respond to higher prices.[243] For instance, Steel Manufacturers asserts that the vast majority of end users do not see hourly price signals because they are retail customers regulated by state commissions.[244] According to Steel Manufacturers, only a small percentage of loads, typically large manufacturing loads, who take electric service through advanced meters will be able to respond to price signals during periods of scarcity. Therefore, they argue that there is no rational justification for imposing all market risks only on such a small pool of retail loads.[245] Further, New Jersey BPU states that demand-side resources that pay a fixed seasonal or annual retail price for electricity will have no reason to respond to any dramatic increase in hourly prices.[246]

180. Similarly, TAPS argues that the proposed rule is not supported by sufficient evidence that lifting such bid caps will attract demand response sufficient to protect consumers from market power.[247] It asserts that when the Commission is relying on demand response to provide the competitive response necessary to keep rates just and reasonable, there must be sufficient empirical proof that actual prices will be just and reasonable.[248] TAPS contends that the Commission has not provided such evidence, and is prepared to ''unleash market forces without making factual findings that the demand response necessary to restrain prices is ready, willing and able to be called upon.'' [249] TAPS also disputes the Commission's statement that artificial bid caps inhibit price signals needed to attract entry by both generation and demand response resources. It asserts that high spot market prices do not correlate with entry in RTO and ISO markets.[250]

181. Pennsylvania PUC states that demand response must be fully integrated into existing markets before price caps can be removed in RTOs and ISOs. It asserts that the Commission wrongly concludes that price caps are inhibiting an otherwise competitive market. It also argues that without infrastructure improvements that permit load to see shortages being priced, removing bid caps would promote the exercise of market power.[251]

182. Similarly, Industrial Coalitions argue that necessary technology and demand response capability must be in place before any changes to mitigation rules can be contemplated. They also state that there are barriers to demand response such as inadequate federal-state coordination, utilities' ability to preclude and frustrate customer participation, and complex participation requirements. Industrial Coalitions ask that the Commission demonstrate how any change in shortage pricing rules will result in lower prices to consumers.[252] SMUD also states that while the elimination of every barrier to demand response is not a prerequisite to easing bid caps for demand response, the problem is that there are still significant barriers to demand response participation that must be addressed first.[253] SMUD reports that there were deficiencies in technology that led the Commission not to allow bid caps to be

[232] NYISO at 4.

[233] ISO New England at 12; *see also* NEPOOL Participants at 16; NSTAR at 3; and Maine PUC at 4–5.

[234] *E.g.*, Alcoa; APPA; California Munis; Industrial Coalitions; Industrial Consumers; LPPC; North Carolina Electric Membership; NRECA; OLD Dominion; TAPS; Steel Manufacturers; SMUD; Public Interest Organizations; New Jersey BPU; and National Grid.

[235] *E.g.*, Alcoa; APPA; NRECA; TAPS; North Carolina Electric Membership; Pennsylvania PUC; LPPC; and Steel Manufacturers.

[236] APPA at 53.

[237] *Id.* at 30–31. The California Munis adopt the comments of APPA on these issues and incorporate them by reference into their comments. California Munis at 17.

[238] NRECA at 16.

[239] LPPC at 3.

[240] *Id.* at 9–10.

[241] *Id.* at 12 (citing *California ex re. Lockyer v. FERC*, 383 F.3d 1006 (9th Cir. 2004, *cert denied, Coral Power, LLC v. Cal. ex rel. Brown*, 127 S. Ct. 2972, 168 L. Ed. 2d 719 (2007); *Interstate Natural Gas Ass'n v. FERC*, 285 F.3d 18, 30–31 (DC Cir. 2002); *Elizabethtown Gas Co. v. FERC*, 10 F.3d 866 (DC Cir. 1993); *Louisiana Energy & Power Auth. v. FERC*, 10 F.3d 866 (DC Cir. 1998)).

[242] LPPC 12–13.

[243] *E.g.*, North Carolina Electric Membership; New Jersey BPU; Old Dominion; Steel Manufacturers; and Pennsylvania PUC.

[244] Steel Manufacturers at 12–13.

[245] *Id.*

[246] New Jersey BPU notes that virtually all New Jersey residential customers and commercial and industrial customers below 100 kW pay fixed retail prices. Therefore, a major increase in wholesale electricity prices during peak hours cannot be expected to attract new demand resources from the large majority of New Jersey customers. New Jersey BPU at 3.

[247] TAPS at 24.

[248] *Id.* at 24–25.

[249] *Id.* at 26. TAPS asserts that the Commission must protect customers from excessive rates and charges, and if it acts without the requisite empirical proof, the Commission will fail to protect consumers. TAPS at 29 (citing, *Atl. Ref. Co.* v. *Pub. Serv. Comm'n of N. Y.*, 360 U.S. 378, 388 (1959)).

[250] TAPS at 26–27.

[251] Pennsylvania PUC at 14–15.

[252] Industrial Consumers at 19.

[253] SMUD at 3 (citing NOPR, FERC Stats. & Regs. ¶ 32,628 at P 109).

lifted previously, and these technologies are still insufficiently developed today.

183. Old Dominion also opposes removing price caps and asserts that efforts to increase demand response should not come at the expense of a customer base that cannot respond to price signals.[254] It states that the Commission should adopt a presumption that such pricing incentives are not necessary and require the RTOs and ISOs that believe otherwise to make a factual demonstration that they are. This would include demonstrating that non-price barriers to demand response have been removed and that current market power mitigation rules will suffice to deal with any gaming behavior.

184. North Carolina Electric Membership states that there is no evidence that generators require higher scarcity payments if the region already has a capacity market.[255] National Grid states that the Commission's proposal to shift revenue from capacity markets to energy markets should not be implemented because it conflicts with the market designs approved by the Commission and implemented in NYISO and ISO New England.[256] New Jersey BPU does not share the Commission's belief that such shortage pricing reforms will automatically lead to lower prices in capacity markets.[257] PG&E states that any proposed shortage pricing rules must be coordinated with other mechanisms that provide similar reliability benefits to electrical systems, including resource adequacy requirements and DR programs.[258] This must include capacity pricing mechanisms. An explanation of such coordination should be a requirement of the filing that RTOs and ISOs make as part of their proposal. PG&E is particularly concerned about the CAISO's implementation of reserve shortage pricing, along with its relaxation of price caps, before meaningful demand response products are available.

185. Comverge and DRAM state that they support the Commission's proposal to reflect the value of energy during times of scarcity. However, they note that they are concerned about how the proposal would impact existing capacity markets, particularly in the longer term.[259] Comverge states that where capacity markets are, or will be, in place each of the four approaches may reduce capacity market prices because revenues from energy and ancillary services would be subtracted from capacity payments. This may discourage participation by some demand response resources in capacity markets.[260] According to DRAM, demand response resources need the ''stable revenue stream'' from the capacity market, and any energy payment received during reliability events is of secondary importance.[261] DRAM states that shortage pricing should not be pursued in a way that requires demand response providers to participate in the energy market because not all customers are suited to, or interested in, energy market participation. Instead, it notes that these customers may participate in a reliability-based demand response program that helps preserve reliability, allowing them to be paid to be a reliability resource. EnerNOC asks the Commission to fashion a policy on shortage pricing that encourages demand response resources to interact in both energy and capacity markets, or in either one, in a manner that is most appropriate for the demand response resource.[262]

186. The FTC encourages the Commission to require that proposals from RTOs and ISOs to lift wholesale bid caps during periods of operating reserve shortages be accompanied by an analysis of how the proposed change in the wholesale bid caps will change the totality of regulatory restrictions on wholesale prices during these periods.[263] Industrial Consumers also state that capacity markets should be suspended prior to any shortage pricing changes to prevent the gaming of multiple markets. They add that shortage pricing without competition is ''monopoly pricing in disguise'' and assert that conditions of true competition must be demonstrated before shortage price is used.[264]

187. PJM Power Providers agrees with the Commission that existing market rules do not accurately reflect the value of energy during periods of shortage and, therefore may deter new entry of demand response and generation resources.[265] They also agree that many of the problems in wholesale electric markets stem from mitigation policies and market design features that suppress prices during shortage conditions below the value of lost load (VOLL). PJM Power Providers notes that in addressing these issues, a balance must be struck to encourage supplies to enter the market while minimizing market power concerns.

188. In this regard, PJM Power Providers notes that scarcity pricing mechanisms need to be integrated into the overall market design in order to be effective, so that prices reflect actual system operation.[266] It states that in the PJM market, pricing does not always match operating procedures. For example, they note that due to startup limitations the system operator may keep a peaking unit operating during non-peak hours so that the unit may be used again later in the day to meet increasing load. While operators should have the flexibility to make these types of decisions, it is critical that prices accurately reflect these operating procedures. Thus, PJM Power Providers states that if the system operator compensates the generator for the cost of keeping a peaking unit operating during non-shortage periods through an uplift charge rather than through the market-clearing price, as is currently the practice in PJM, this practice ''must be fixed.'' It states that the shortage pricing mechanism should be coupled with a new ''reserve product'' so that the scarcity price reflects the opportunity cost of held reserves (the cost of operating the peaking unit during no-scarcity periods) in a manner that is consistent with the overall shortage pricing rules. Finally, PJM Power Providers states that to achieve the intended results, the Commission must provide that when a contingency or constraint related to operations and reserves is seen in either the day-ahead or real-time market, shortage pricing should be reflected in the energy market as well.

189. Finally, TAPS makes two recommendations. The first is that the Commission should maintain some type of ''safety net cap'' that will protect consumers against ''stratospheric'' prices.[267] The second is that if the Commission does approve some shortage pricing rules, it must also revisit its approval of RTO and ISO capacity markets that were justified on the basis that such caps prevented generators from earning revenues needed to recover investment costs.[268] It argues that if spot market prices can rise to the levels claimed to be needed to recover generator investment costs, a

[254] Old Dominion at 14.

[255] North Carolina Electric Membership at 9.

[256] National Grid at 23.

[257] New Jersey BPU at 5.

[258] PG&E at 11.

[259] DRAM at 23.

[260] Comverge at 21–23.

[261] DRAM at 24.

[262] EnerNOC at 14.

[263] FTC at 29.

[264] Industrial Consumers at 19.

[265] PJM Power Providers at 3.

[266] *Id.* at 4.

[267] TAPS at 43.

[268] For example, TAPS notes that a primary justification of ISO New England's locational installed capacity market proposal was that caps take away revenues needed for cost recovery. *Id.* 43–44.

principal justification for organized capacity markets is eliminated, and consumers will be subjected to the high energy prices that the capacity market was intended to replace.

190. Several commenters address the Commission's requirement that RTOs and ISOs proposing shortage pricing reforms address the adequacy of any market power mitigation measures and that the Commission will solicit the views of the Independent Market Monitor for each RTO and ISO on any proposed reforms. EEI states that the Commission is correct to address concerns regarding the exercise of market power by requiring that any proposed reforms be supported by an adequate record demonstrating that provisions exist for mitigating market power and deterring gaming behavior.[269] EEI agrees that the Commission should solicit input from the Independent Market Monitor on any proposed rule changes in this area. Old Dominion states that the Commission should adopt a presumption that such pricing incentives are *not* necessary and require the RTOs and ISOs that believe otherwise to make a factual demonstration that they are.[270] This would include demonstrating that non-price barriers to demand response have been removed and that current market power mitigation rules will suffice to deal with any gaming behavior. Public Interest Organizations urge that before current market mitigation rules are relaxed, resource adequacy requirement must be in place and that an independent market monitor must be able to monitor shortage pricing behavior very closely.[271] TAPS states that the Commission needs to strengthen the factual showing that RTOs and ISOs must make with respect to shortage pricing reforms[272] to include at least six analyses: (1) Address market power under scarcity conditions; (2) measure whether demand response successfully mitigates market power, including empirical evidence, such as critical loss analyses; (3) examine the incentive and ability of demand response resources to engage in withholding of their demand response resources; (4) demonstrate that market power mitigation methods are effective during shortage periods for any resource, demand or generation, that can affect prices; (5) determine if there is enough demand response available to respond under scarcity conditions; and (6) prepare statistics on past and expected frequency of scarcity events as an indication of the effectiveness of policies to ensure resource adequacy.

191. Comverge and DRAM express concerns about ''price averaging'' and its possible adverse impact on demand response resource participation in organized markets. DRAM recommends time-differentiated capacity payments based on loss-of-load probability or loss-of-load expectation as an alternative to raising price caps during a period of operating reserve shortage as a means of removing a barrier to demand response resources.[273]

ii. Commission Determination

192. In this Final Rule, the Commission adopts the proposed rule on price formation during times of operating reserve shortage. The Commission continues to find that existing rules that do not allow for prices to rise sufficiently during an operating reserve shortage to allow supply to meet demand are unjust, unreasonable, and may be unduly discriminatory. In particular, they may not produce prices that accurately reflect the value of energy and, by failing to do so, may harm reliability, inhibit demand response, deter entry of demand response and generation resources, and thwart innovation.

193. When bid caps are in place, it is not possible to elicit the optimal level of demand or generator response, thereby forgoing the additional resources that are needed to maintain reliability and mitigate market power. This, in turn, increases the likelihood of involuntary curtailments and contributes to price volatility and market uncertainty. Further, by artificially capping prices, price signals needed to attract new market entry by both supply- and demand-side resources are muted and long-term resource adequacy may be harmed. Without accurate prices that reflect the true value of energy, we cannot expect the optimal integration of demand response into organized markets.

194. Therefore, we are taking action to remove such barriers to demand response by requiring price formation during periods of operating shortage to more accurately reflect the value of such energy during such shortage periods. Each RTO or ISO is required to reform or demonstrate the adequacy of its existing market rules to ensure that the market price for energy reflects the value of energy during an operating reserve shortage. The RTO or ISO is required to provide, as part of its compliance filing, a factual record that includes historical evidence for its region regarding the interaction of supply and demand during periods of scarcity and the resulting effects on market prices, an explanation of the degree to which demand resources are integrated into the various markets, the ability of demand resources to mitigate market power,[274] and how market power will be monitored and mitigated, among other factors.

195. Some commenters oppose price reforms during periods of shortages on grounds that such reforms may lead to the exercise of market power and will result in unjust and unreasonable rates. They argue that the Commission is abdicating market mitigation by allowing price caps to be removed during a power shortage. We disagree. To the contrary, the Commission is not taking any action to remove market mitigation in regional markets. Each of the Commission's proposed reforms includes some form of mitigation, either bid caps, administratively-determined prices, or prices tied to payments made in emergency demand response programs administered by RTOs or ISOs (and thus approved by the Commission). RTOs and ISOs are free to propose other pricing reforms and associated mitigation that meet the criteria herein. Moreover, these reforms to enhance demand responsiveness further mitigate seller market power by allowing demand to choose to not consume power when the price is higher than they wish to pay. Allowing buyers to respond to prices reduces incentives for a seller to manipulate market prices.[275]

196. To guard the consumer against exploitation by sellers, we adopt the proposal to require RTOs and ISOs to adequately address market power issues in the compliance filings directed herein. We require an adequate factual record demonstrating that provisions exist for mitigating market power and deterring gaming behavior to be part of a compliance filing for price reform during periods of operating reserve shortage. This could include, but is not limited to, the use of demand resources to discipline bidding behavior to competitive levels during an operating reserve shortage. We also intend to closely monitor market behavior during periods of operating reserve shortage to

[269] EEI at 19.

[270] Old Dominion at 15.

[271] Public Interest Organizations at 9.

[272] TAPS at 29.

[273] Comverge at 10; DRAM at 10.

[274] As discussed further below, demand resources are the set of demand response resources and energy efficiency resources and programs that can be used to reduce demand or reduce electricity demand growth.

[275] *See* B.F. Neenan *et al.,* Neenan Associates, *2004 NYISO Demand Response Program Evaluation,* at E–5, (Feb. 2005); David B. Patton, Potomac Economics, *2006 State of the Market Report—The Midwest ISO,* at 44 (May 2007).

ensure that market participants are following market rules and to guard against the exercise of market power.

197. For purposes of providing the Commission with an adequate factual record regarding its shortage pricing proposal, the RTO or ISO must address the six criteria that we adopt below,[276] several of which refer to demand resources. For these purposes, ''demand resources'' refers to the set of demand response resources and energy efficiency [277] resources and programs that can be used to reduce demand or reduce electricity demand growth. Although the Final Rule requires provisions related to RTO or ISO ancillary services markets, aggregation by ARCs and deviation penalties to be implemented for demand response resources, we believe it is appropriate to allow the RTO or ISO to support its shortage pricing proposal with reference to the broader set of demand resources.

198. We note that this Final Rule does not eliminate or otherwise revise the market power mitigation measures that remain in place during times when operating reserves are insufficient. For example, conduct and impact tests are applied in ISO New England, NYISO, and Midwest ISO. A pivotal supplier test is used in PJM. Further, PJM and CAISO mitigate bids by generators that are chosen out-of-merit order.

199. Existing rules should combine effectively with the more vigilant monitoring required in this rule to dissuade the exercise of market power. Further, as noted in the NOPR, the pricing reform established in this Final Rule is only one part of the continuing effort by the Commission and RTOs and ISOs to improve the functioning of organized markets.

200. TAPS recommends a ''safety net cap'' to protect against very high prices and for a review of the need for capacity markets if there is shortage pricing. As stated earlier, none of the four approaches suggested by the Commission precludes a limit on prices. For example, the first approach does not propose necessarily to eliminate bid caps; instead, ''bid caps would be allowed to rise above existing caps'' (as stated in the NOPR) during an operating reserve shortage. No explicit amount of increase is stated or required under the first suggested approach. Under the second approach, a demand curve for operating reserves is commonly capped at some multitude of the expected cost of new entry (for instance, one and a half times the cost of new entry). The market-clearing price under the fourth approach—allowing the payment made to emergency demand response providers to set the market-clearing price—depends on that payment. As such, the approaches already account for a ''safety net'' cap.

201. TAPS and others also recommend examining the need for capacity markets under shortage pricing and whether customers would be charged twice. Under all existing capacity market rules, the revenues earned from the sale of energy and ancillary services are accounted for in the calculation of capacity payments so that customers will not be double charged. Comverge and DRAM suggest addressing price averaging in capacity markets as an alternative to raising price caps during periods of operating reserve shortages. The Commission has noted previously that this rulemaking is not designed to address capacity market issues and, therefore, finds their comments to be outside the scope of this proceeding.

202. Some commenters argue that end users are not able to see hourly prices and, therefore, will not respond to a shortage price signal. Similarly, several commenters argue that demand response capability must be in place before changes to mitigation rules are considered. Demand response programs that currently allow a fraction of the load to respond can have a positive effect on system reliability and market demand and help reduce prices for all. Full deployment of advanced meters and complete participation by all load is not needed to help cope with operating reserve shortages.[278] In addition, the Commission establishes six criteria, as discussed below, to evaluate an RTO's or ISO's proposal—criteria designed to ensure that the shortage pricing proposal achieves the objectives of this requirement while protecting customers from market power.[279]

203. Further, with better price signals, more buyers would find it worthwhile to invest in technologies that allow them to respond to prices. Also, while some customers may not be able to respond to hourly prices, they will see monthly bills and have an incentive to reduce use of power in general by, for example, setting air conditioning thermostats higher during peak periods or simply when the weather forecast calls for high temperatures, or engaging in energy efficiency, which can lead to an overall reduction in market demand, reduced need for marginal resources, and fewer periods of shortage. Further, we reiterate that such price signals would encourage entry by generators, investment in new technology, and more participation in demand response programs.

204. Several commenters are concerned that some demand response resources would be negatively affected by the shift of revenues from capacity markets to energy markets. In general, giving resource suppliers and customers more choices for how they participate in markets is beneficial. Shortage pricing in an emergency and capacity markets for long-term resource adequacy assurance serve largely distinct purposes, but we agree that they should not work at cross purposes. Adding any new element to a market design can have effects on the other elements. We require that each RTO and ISO address in its compliance filing how its selected method of shortage pricing interacts with its existing market design.

205. We disagree with LPPC's claim that higher prices during shortage periods will destabilize long-term arrangements. Allowing prices to rise during emergencies should instead provide an incentive for customers to increase their hedging through long-term contracting. Further, as noted above, it should also encourage investment in demand response technology and provide an incentive to market participants to participate in load response programs, thereby mitigating the expected higher prices.

206. Our requirement that RTOs and ISOs provide a factual record to demonstrate the adequacy of market power mitigation measures, coupled with the Commission's solicitation of the views of each RTO's and ISO's Market Monitoring Unit on proposed shortage pricing reforms, as supported by EEI, should address the concerns of

[276] *See* discussion *infra* P 247.

[277] The Commission's Staff has defined energy efficiency to refer to using less energy to provide the same or improved level of service to energy consumers in an economically efficient way. Energy efficiency uses less energy by employing products, technologies, and systems to use less energy to do the same or better job than by conventional means. Energy efficiency saves kilowatt-hours on a persistent basis, rather than being dispatchable for peak hours, as are some demand-response programs. Energy efficiency can include switching to energy-saving appliances (such as Energy Star(r) certified products) and advanced lighting (compact fluorescent or LED lighting); improving building design and construction (better insulation and windows, tighter ductwork, use of high-efficiency heating, ventilation, and air conditioning); and redesigning manufacturing processes (advanced electric motor drives, heat recovery systems) to use less energy, thus reducing use of electricity and natural gas. Federal Energy Regulatory Commission, *Assessment of Demand Response & Advance Metering: Staff Report at A–4 (September 2007).*

[278] *See* Federal Energy Regulatory Commission, *Assessment of Demand Response and Advanced Metering: Staff Report,* Docket No. AD06–2–000, at 7. As little as five percent of load responding to a high price can avert a system emergency and may help to lower the market price.

[279] *See* discussion *infra* at P 247.

Old Dominion, Public Interest Organizations, and TAPS regarding the ability of market participants to exercise market power during periods of operating reserve shortages.

207. Finally, we address PJM Power Providers' concerns that shortage pricing mechanisms be integrated into the overall market design of the RTO, perhaps with a new ''reserve product,'' and the need for contingencies or constraints related to reserves that is seen in the day-ahead or real-time market to be reflected in the energy market. We share PJM Power Providers' concern about out-of-merit order generation, such as the example they cite, and it being reimbursed through up-lift charges. A market works more efficiently when all decisions of the system operator that affect costs, *e.g.,* running peaking units, are reflected in market prices rather than in uplift charges. We encourage all RTOs and ISOs to consider this when evaluating their existing shortage pricing rules or developing new ones. This might include, as PJM Power Providers describes it, the development of ''new reserve products.'' As to their second concern, we also agree that the better integrated markets are with one another, the more efficiently they will operate. However, the aim of this rulemaking, maintaining reliability through entry of new generation and demand response resources, need not be achieved through one particular market rule structure.

b. Four Approaches

208. In the NOPR, the Commission proposed to require each RTO or ISO to make a compliance filing proposing any necessary reforms to ensure that the market price for energy accurately reflects the value of such energy during an operating reserve shortage. Given regional differences in market design, the Commission did not propose to require one particular approach to achieving this reform. Rather, the Commission stated that each RTO or ISO may propose one of four suggested approaches or another approach that achieves the same objectives. The four approaches are: (1) RTOs and ISOs would increase the energy supply and demand bid caps above the current levels only during an emergency; (2) RTOs and ISOs would increase bid caps above the current level during an emergency only for demand bids while keeping generation bid caps in place; (3) RTOs and ISOs would establish a demand curve for operating reserves, which has the effect of raising prices in a previously agreed-upon way as operating reserves grow short; and (4) RTOs and ISOs would set the market-clearing price during an emergency for all supply and demand response resources dispatched equal to the payment made to participants in an emergency demand response program.

i. Comments

209. Many commenters spoke for or against all four approaches collectively. Those in support state that each of the four approaches is an appropriate means for achieving the goals of the NOPR's proposal on shortage pricing. Supporters of all four approaches typically did not address each approach individually, and their comments are included above among those who spoke in support of the overall proposal. Similarly, many of the commenters that oppose the overall proposal and all four approaches are also summarized above, but a few of these make more detailed collective comments on the NOPR's four suggested approaches, which are presented next. For example, NRECA and APPA state that they are firmly opposed to the Commission's four approaches to change pricing rules during shortage situations and base their opposition on the fundamental disagreement that current prices during shortage periods are unjust and unreasonable.[280] NRECA states that the approaches put forward by the Commission would result in rates that are unjust and unreasonable, and would, at a minimum, grant windfall profits to those suppliers that have been found by the RTOs' and ISOs' market monitors to possess market power. APPA also states that it does not support any of the four proposed shortage pricing approaches.[281] Public Interest Organizations state that it cannot support any of the Commission's proposed approaches at this time because demand response participation is not at a level that will assure customers that prices will be just and reasonable.[282] Public Interest Organizations urge that before current market mitigation rules are relaxed, a resource adequacy requirement must be in place and market access and effective demand response resource participation must be demonstrated. It also states that an independent market monitor must be able to monitor shortage pricing behaviors very closely.

210. Numerous commenters spoke for or against some of the four approaches, and their comments on each approach are discussed next.

211. Among those who favored one or more of the four approaches, the demand curve for operating reserves (the third approach) received the most and strongest support.

212. Under the first approach, RTOs and ISOs would increase energy bid caps (for each bidder) and the price cap (for the market-clearing price) above the current level, but only during an operating reserve shortage.[283] PJM Power Providers supports this approach and notes that to avoid market power concerns, bids may be assessed for the potential of economic withholding by considering the value of lost load multiplied by the increased probability of outages. FirstEnergy supports lifting bid caps during a shortage if the shortage is genuine, wholesale prices are reflected in retail rates, and energy and demand response are treated on a comparable basis.[284] Ohio PUC states that it would recommend this approach only where there are a sufficient number of suppliers or enough demand response to check the exercise of market power.[285] In commenting on the four approaches, Mr. Borlick notes that the Commission has correctly concluded that energy prices during periods of supply shortage fail to accurately reflect the value of load reduction.[286] Mr. Borlick states that approach 1 would produce energy prices high enough to accurately reflect the marginal value of consumption but would also encourage generators to exercise market power both through economic and physical withholding. Of the four approaches proposed in the NOPR, Mr. Borlick states that this is the least desirable. He states that approach 2 is superior to approach 1 because it would allow the demand side to set economically efficient clearing prices while controlling economic withholding by generators, although generators could still physically withhold capacity. Its drawback is that it does not provide a vehicle for efficiently trading off operating reserves for energy production.

213. NRECA opposes the first approach because it would remove price caps that have been established to mitigate market power, exposing consumers to the price bid by the marginal resource. NRECA asserts that the market-clearing price during a

[280] NRECA at 23.

[281] APPA at 29.

[282] Public Interest Organizations at 17.

[283] For example, PJM may choose to increase its current market-wide price cap. Another RTO or ISO could lift individual generator bid caps while keeping its market-wide price cap at its existing level. What exactly will be changed under this proposal depends on existing rules and what the RTO or ISO stakeholders consider for that region's market design and on what the RTO or ISO then proposes in its compliance filing.

[284] FirstEnergy at 11.

[285] Ohio PUC at 10–11.

[286] Mr. Borlick at 5.

system emergency could potentially exceed the cost of the marginal resource dispatched and the cost of new entry.[287] Similarly, TAPS opposes the first approach because it offers consumers no protection against the exercise of market power and thus would only produce unjust and unreasonable rates.[288] TAPS notes that if demand response is insufficient to restrain prices, the Commission would have to rely on generators, who have neither the ability nor the incentive to set a price that is just and reasonable under shortage conditions.[289]

214. Other commenters present a variety of reasons for not supporting the first approach. NEPOOL Participants argues that imposing either of the first two approaches in ISO New England could have unintended effects on New England markets because many market participants agreed to the forward capacity market with the understanding that the $1000/MWh cap on ''energy offers and bids'' would not be removed.[290] Maine PUC claims that in New England, it is particularly unreasonable to impose a requirement to remove bid caps from the energy market or take other steps that remove consumer protections prior to a showing that consumers can change their behavior to avoid being harmed.[291]

215. Comverge asserts that the first approach may invite gaming: generators could withhold capacity so that emergency conditions occur and then take advantage of the ensuing higher prices. However, it states that if a much more dispatchable demand response and voluntary price-response were in place the potential for gaming would be substantially reduced.[292] Duke Energy states that it is unrealistic to expect resources to accurately predict emergency conditions and tailor their bids appropriately. Thus, it states that this approach would provide generation owners with an incentive to bid above cost, putting upward pressure on prices.[293]

216. Potomac Economics recommends that the Commission not encourage this approach because it believes that the theory implicit in this approach is flawed. It states that when the system is in a shortage, relying on supply offers is not the action generally taken by system operators. Also, if suppliers do not have market power, they will not have an incentive to raise the price of their offers. Therefore, it concludes that pursuing an approach that relies on suppliers to raise their offers to achieve efficient price signals during shortage conditions would not be reliable.[294]

217. NRECA states that, in presenting the first and second approaches, the NOPR uses the terms bid caps, offer caps, and price caps interchangeably and asks the Commission to specifically define these terms. North Carolina Electric Membership also notes that the NOPR does not clearly distinguish between a generation offer cap in place as a result of mitigation procedures and the $1,000/MWh umbrella energy offer cap ceiling in place in most RTOs and ISOs.[295]

218. Under the second approach, RTOs and ISOs would raise bid caps above the current levels only for demand bids, that is, for bids by customers expressing their willingness to pay more than the market price cap to continue to receive power during an emergency and hence perhaps avoid being curtailed. Ohio PUC states that lifting the caps for only demand bids during system emergencies is a reasonable approach for creating transparent price signals in shortage situations.[296]

219. NRECA opposes this approach because these demand bids would set the market-clearing price paid to all resources, including generators. This would result in customers paying rates to generators that exceed the costs of the most expensive generator available on the system, even if those generators do nothing unusual to alleviate the emergency condition.[297] TAPS states that this approach could also raise market power concerns if the market participant submitting a demand bid also had generation that could benefit from a price increase.[298]

220. Duke Energy and FirstEnergy do not support this approach because generation resources would be treated differently from load, which is inconsistent with the comparability principle the Commission proposes for demand resources.[299]

221. Under the third approach, RTOs and ISOs would establish a demand curve for operating reserves, which establishes a predetermined schedule of prices according to the level of operating reserves. As operating reserves become shorter, the price increases. Many commenters support this approach and state that it should be implemented.[300] Several commenters assert that this approach: (1) Is the most efficient means of moving prices toward the value of lost load during emergency situations;[301] (2) would promote reliability by providing greater and timely incentives for market participants to provide capacity;[302] (3) can allow RTOs and ISOs to set prices that more accurately reflect the costs of meeting demand and reserve requirements during power shortages;[303] and (4) avoids various concerns regarding the exercise of market power. PPL Parties note that the Commission has already approved this approach for the ISO New England, NYISO, and Midwest ISO markets.[304] Dominion Resources also emphasizes that the demand curve for operating reserves has proved to be a workable method in ISO New England.[305] Of the four approaches, Mr. Borlick states that approach 3 is the most appealing based on economic theory; however, it poses implementation problems because of the computational burden involved in developing a demand curve that would accurately reflect the value of consumption.[306]

222. Potomac Economics states that implementing a demand curve for operating reserve is critical for achieving efficient shortage pricing and should be a required element for RTO or ISO markets.[307] It states that such demand curves are most effectively implemented in the context of jointly-optimized energy and ancillary services markets. It believes that effective shortage pricing requires jointly-optimized markets with operating reserve demand curves set at levels that reflect the value of reliability that the operating reserves provide to consumers.[308] However, Potomac

[287] NRECA at 20.

[288] TAPS at 40.

[289] *Id.*

[290] NEPOOL Participants at 17.

[291] Maine PUC at 5.

[292] Comverge at 21.

[293] Duke Energy at 9.

[294] Potomac Economics at 4–5.

[295] *Id.*

[296] Ohio PUC at 12.

[297] NRECA at 20.

[298] TAPS at 41–42.

[299] Duke Energy at 9; First Energy at 11.

[300] *E.g.*, Ameren; Mr. Borlick; Constellation; Duke Energy; Exelon; FirstEnergy; Potomac Economics; PJM Power Providers; and PPL Parties.

[301] Duke Energy at 10. Duke Energy explains that the use of predetermined demand curves provides a structure under which the price of energy rises to the level of the value of lost load when firm loads are interrupted. As the probability of falling below target reserve levels rises, the price of energy and reserves also rises. Any load that wishes to respond to higher prices would take appropriate action to curtail demand. Duke Energy believes that the use of such shortage pricing is essential to elicit broader demand response. *Id.* (citing Robert Stoddard Affidavit, Duke Energy ANOPR Comments).

[302] PJM Power Providers at 6.

[303] Ameren at 28.

[304] PPL Parties at 6.

[305] Dominion Resources at 7.

[306] Mr. Borlick at 8.

[307] Potomac Economics at 5.

[308] *Id.* at 6.

Economics states that the third approach alone is not sufficient and that the fourth approach, allowing payments to emergency demand response resources to set the market-clearing price is a valuable complement.[309] It notes that RTOs and ISOs can call on emergency demand response or interruptible retail load to maintain reliability. These forms of demand response are not integrated into the market, and therefore some form of the fourth approach is needed to set efficient shortage prices when the demand response of emergency demand response providers is called on in an emergency.[310]

223. PJM Power Providers proposes that PJM should use a downward-sloping operating reserve demand curve simultaneously for both energy and operating reserves, instead of having a fixed operating reserve requirement. It notes that this would (1) remove certain anomalies that occur with the current fixed requirement, (2) provide an adequate incentive for ''increased energy demand bidding,'' and (3) improve reliability by providing greater and timely incentives for market participants to provide capacity.[311] Constellation supports the approach of using a demand curve for operating reserves. While acknowledging this approach presents practical problems associated with developing the demand curve, Constellation states that these can be addressed and the benefits of this solution justify efforts to deal with these challenges.[312] Exelon states that the demand curve for operating reserves, the Commission's third approach, would be the most effective of the four approaches (although it recommends an alternative approach, reported below) because it would help induce additional demand response during periods of peak demand. FirstEnergy states that an administratively set demand curve is an acceptable way to set the operating reserve price in times of shortage because the demand side of the market is underdeveloped and cannot respond to market forces on the same scale as supply-side resources. It states that a demand curve can effectively mitigate market power where one market participant becomes the last available supplier in a shortage.[313]

224. NRECA opposes the demand curve for reserves approach because it is designed to raise the price above the current maximum level allowed. TAPS states that the third approach risks mandating a particular type of reform, an RTO-run ancillary services market, rather than a reform that originates with stakeholders.[314]

225. Ohio PUC does not support the third approach because a demand curve for operating reserves may not ensure that any new generation will be built.[315] Comverge states that the third approach is difficult to implement because it requires an administrative determination of the demand curve's characteristics.[316]

226. Under the fourth approach, RTOs or ISOs would set the market-clearing price during an operating reserve shortage at the payment made to participants in an emergency demand response program. PJM Power Providers states that this fourth approach is reasonable, but notes that when operating reserves and locational reserve requirements decline below target levels despite use of the fourth approach, the question of how to set and adjust the price must then be addressed.[317]

227. TAPS states that the fourth approach appears to allow market-clearing prices to be set by the RTO or ISO at whatever payment an RTO or ISO makes to a demand response resource that reduces consumption during emergencies in return for a contractually established payment that, perhaps, was determined by a regulatory body other than the Commission and, therefore, would be outside of the Commission-approved market-clearing mechanism and on that basis rejects it.[318] Comverge believes that the fourth approach presents two issues: (1) Participants are likely to ignore the market value of demand response before an emergency is declared; and (2) the emergency value of demand response would be substituted for the market value of power, which may reinforce the use of demand resource as an emergency-only resource.[319] Similarly, Duke Energy states that this proposal is questionable because it would be difficult to determine exactly what price would be paid to non-demand response market participants, and the program price paid to participating demand response resources may not actually reflect these participants' or other parties' economic assessment of the hourly value of power. Emergency demand response resources do not submit bids, but just receive a payment, against which they must judge the cost of forgoing energy. Because there is no solicitation of value from resources, it would be difficult and unreliable to determine a single price that would be suitable both for the interrupted emergency demand response providers and for payment to other resource providers.[320] Mr. Borlick gives approach four the most favorable review on the basis that it creates an incentive of demand response to bid its true interruptible cost and, therefore is more likely to produce economically efficient prices.[321]

228. Ameren particularly objects to the fourth approach because of the market distortion and unintended consequences it could cause. It states that load should receive payments for demand response only if the load clears in the day-ahead market, and its payment should be based on the bid that the market participant submitted.[322] Ohio PUC does not support the fourth approach, stating that it falls short of resolving the problem at hand.[323]

229. A few commenters offer new approaches or variations on one of our four suggested approaches. EPSA points to the 2007 PJM State of the Market Report to assert that other approaches besides these four should be considered. Specifically, in that report PJM's market monitor, Joseph Bowring, recommended that shortage pricing should be defined in several stages with different pricing in each stage. While EPSA does not specifically endorse this proposal, it states that such a proposal should be considered.[324]

230. Exelon suggests a variation on the Commission's proposed shortage pricing approaches. Exelon proposes a price cap in the market that would ratchet up as shortage conditions worsen.[325] This price cap would rise to predetermined levels as a shortage situation approaches. In essence, this would work like a demand curve, with the price cap increasing as the amount of available operating reserves diminished. Under this approach, the administratively set price levels would function as a moving cap and the market would determine the value of supply, up to that administratively set price cap.[326] Exelon maintains that this approach would elicit demand response to alleviate the shortage before it becomes a real crisis. It makes the point

[309] *Id.* at 7.

[310] *Id.*

[311] PJM Power Providers at 7.

[312] Constellation at 13.

[313] FirstEnergy at 11–12.

[314] TAPS at 42.

[315] Ohio PUC at 11.

[316] Comverge at 22.

[317] PJM Power Providers at 8.

[318] TAPS at 42.

[319] Comverge at 22.

[320] Duke Energy at 10 (citing Robert Stoddard Affidavit, Duke Energy ANOPR Comments at 16).

[321] Mr. Borlick at 9.

[322] Ameren at 28–29.

[323] Ohio PUC at 12.

[324] EPSA at 10.

[325] Exelon at 11.

[326] *Id.* at 12.

that no bids under this cap would be subject to mitigation procedures. Exelon believes that this approach is superior because it allows the market to determine the value of supply, within the cap, rather than requiring the market administrator to impose a value.

231. NRECA offers what it says is a variation on the second approach, and APPA and TAPS support this alternative. They propose allowing only demand response resources to bid higher than the current caps. Demand response resources would be paid the resulting clearing price, but generating resources would not. Instead, generators would receive the highest clearing price among the generating resources. NRECA explains that this approach would encourage additional demand response by allowing demand response resources to obtain a higher price for their response during emergencies. Specifically, it states that this proposal would: (1) Encourage additional demand response; (2) contribute to maintaining reliability; (3) help achieve the needed balance between demand and supply on a real-time basis; and (4) not shift rents from consumers to those generators whose market power must be mitigated by supply bid caps in the first place.[327] TAPS states that if properly implemented, this proposal should not incent generators to create emergencies because they would not profit from them and, although this proposal would add to the uplift consumers must bear, it would not exact the same degree of extreme hardship on consumers as elevating the market-clearing price across ''swaths of the nation.'' [328] TAPS asserts that this alternative proposal is an effective way for the Commission to gather data on the willingness of demand response to come to market and on the relative costs of the uplift associated with this method versus allowing the demand response price to be the market-clearing price. In order to guarantee that such a proposal would be allowable, TAPS suggests changes to the proposed regulatory language and the definition of ''operating reserve shortage.'' [329] Like NRECA, Steel Manufacturers indicates that it would support the removal of bid caps for demand response resources during a system emergency if the higher bids do not set the market-clearing prices.[330]

232. Comverge recommends an alternative approach that allows price caps to be relaxed as the market adds more dispatchable, price-responsive demand response. It states that this would allow for use of the best forms of market power mitigation: dispatchable demand response and customer price response.[331]

233. Potomac Economics states that the Commission should add to the four approaches provisions that would set efficient prices when the RTOs and ISOs take other emergency actions under shortage conditions, including emergency transactions, export curtailments, voltage reductions, and other emergency actions.[332]

ii. Commission Determination

234. Although we require RTOs and ISOs to modify, where necessary, their market rules governing price formation during periods of operating reserve shortage, we will not mandate any specific approach to this reform. Rather, because each market design is different, the changes to market rules should reflect each region's market design. To that end, each RTO or ISO may propose one of four approaches or another approach that achieves the same objectives. Each RTO or ISO should work with its stakeholders to develop a program that is appropriate for its region. Each of the four suggested approaches can be fashioned in a reasonable way upon compliance to achieve the objectives of the reform required here.

235. We address comments on the four approaches below. We will not address individually each comment on the four approaches provided by the Commission because we are not mandating one specific approach that all RTOs and ISOs must follow, and because each RTO and ISO must demonstrate that it currently complies with the rule or has a proposal that will put it in compliance. We cannot make a determination at this point that any particular approach as offered by an RTO or ISO is superior to another. Indeed, that is why a menu of options is offered here. One method of pricing during shortage situations may work better than another for any one RTO or ISO. All four of the approaches presented by the Commission have the potential to meet the goals of this rulemaking: maintaining reliability, eliminating barriers to the comparable treatment of demand response, and allocating energy during a shortage to those who value it most. Any filing by an RTO or ISO will be judged according to the criteria set forth in this Final Rule. We are also requiring the Independent Market Monitor for each RTO and ISO to provide us with its view on any proposed reforms. Finally, any proposal put forth by an RTO or ISO that follows a path different from the four approaches offered here must meet the same criteria set forth above. Only when an RTO or ISO submits a compliance filing can and will the Commission determine if its pricing rules are just and reasonable, not unduly discriminatory and sufficient to meet the stated goals of this rulemaking.

236. NRECA and North Carolina Electric Membership seek clarification on the terms bid cap, offer cap, and price cap. Bid cap refers to the maximum price that a seller (generation or demand response resource) or buyer may bid (*i.e.*, offer to sell or buy) energy.[333] The term price cap refers to a limit on the price of energy in an organized market.[334] In this rulemaking we have restricted our usage to bid cap or price cap, as appropriate.

237. Several commenters offer alternative approaches to modifying shortage pricing rules. In the NOPR we asked commenters to provide us with, not just barriers, but potential solutions, and these commenters have done just that. While we will not adopt any of these proposed changes explicitly in this rule, we note that RTOs and ISOs and their stakeholders are free to consider these and other possible solutions and propose to us their own method of shortage pricing reform that satisfies the criteria as well as our four approaches.

c. The Commission's Proposed Criteria

238. The Commission proposed to adopt further requirements to ensure that any proposed reforms of shortage pricing rules or demonstrations of the adequacy of existing rules in the area of shortage pricing have adequate factual support and that RTOs and ISOs show how the proposed reforms are designed to protect consumers against the exercise of market power.[335] First, each RTO or ISO proposing to reform or demonstrate the adequacy of its existing market rules in this area must provide an adequate factual record for the Commission to evaluate its proposal. This factual record will allow the Commission to discharge its duty to ensure that any reform is just and reasonable, not unduly discriminatory, and appropriately tailored to the

[327] NRECA at 17.

[328] TAPS at 37.

[329] *Id.* at 39.

[330] NRECA at 17; Steel Manufacturers at 13.

[331] Comverge at 22.

[332] Potomac Economics at 7.

[333] Although bid cap and offer cap have the same meaning in the NOPR, we use only the term bid cap to avoid confusion.

[334] For example, a particular generator may have a bid cap of $100 and bid $100 but be paid a higher market-clearing price. A price cap is a limit on the market-clearing price.

[335] NOPR, FERC Stats. & Regs. ¶ 32,628 at P 118.

circumstances in the RTO's or ISO's region. Second, the Commission proposed that any change in market rules to implement the proposed reforms must consider the issue of market power and the RTO or ISO proposing reform must address the adequacy of any market power mitigation measures that would be in place during an operating reserve shortage. In addition, to ensure an adequate record on the issue of market power mitigation, the Commission proposed to solicit the views of the Independent Market Monitor for each RTO or ISO region on any proposed reform.

239. Further, the Commission stated that it would consider the factual record compiled by the RTO or ISO to determine whether its proposal, or its demonstration of the adequacy of its existing market rules, meet six criteria, namely, that the proposal would:

- Improve reliability by reducing demand and increasing generation during periods of operating reserve shortage;
- Make it more worthwhile for customers to invest in demand response technologies;
- Encourage existing generation and demand resources needed during an operating reserve shortage to remain in business;
- Encourage entry of new generation and demand resources;
- Provide comparable treatment and compensation to demand resources during periods of operating reserve shortages; and
- Have provisions for mitigating market power and deterring gaming behavior, including, but not limited to, use of demand resources to discipline bidding behavior to competitive levels during periods of operating reserve shortages.

240. The Commission requested comment on whether these criteria are appropriate and whether there are additional criteria that we should consider in evaluating a proposal for pricing during a period of operating reserve shortage by RTOs and ISOs.

i. Comments

241. Duke Energy supports the proposed criteria to evaluate RTO's and ISO's filings on proposed reforms for shortage pricing. Wal-Mart states that the criteria are a reasonable approach to providing guidance to RTOs and ISOs in their reform proposals.[336] EPSA states that the Commission must be clear in the Final Rule on the principles and the criteria which underpin its proposal.[337]

242. Comverge states that it supports each of the six proposed criteria to demonstrate the merits of new energy market rules and the Commission's proposed rulemaking approach for each respective RTO or ISO. However, it recommends that the Commission add the following criterion: ''where applicable, require a detailed assessment of the impact of new energy market rules on the respective capacity market participants.'' [338]

243. North Carolina Electric Membership states that if the Commission adopts the proposed rule on price reform during shortage periods, the Commission should adopt additional criteria to protect consumers against the exercise of market power, similar to the minimum protections included in the PJM shortage pricing settlement.[339] It suggests that the Commission should also require RTOs and ISOs to show that any shortage pricing will: (1) Protect consumers in the most vulnerable and smallest load pockets where access to available resources is significantly constrained even in non-shortage conditions; (2) define explicit triggers for when shortage prices will apply; (3) ensure that the extra revenues received by generators will be included in the energy and ancillary service revenue offset to capacity market clearing prices paid in forward capacity markets; and (4) require that RTOs and ISOs work with stakeholders to develop a program for setting prices during a power shortage that is acceptable to all.[340]

244. Similarly, PG&E states that the proposed criteria should be expanded to include the following: (1) A demonstration that any proposed market rule changes are cost effective, including an evaluation of the impact on reliability and an estimation of the cost of the program; (2) an evaluation that the operating reserve shortage pricing mechanism is adequately coordinated with other key market mechanisms; and (3) an assessment of the readiness of demand response programs that will be called upon to reduce the number and severity of shortage pricing events and help mitigate market power.[341]

245. TAPS asserts that the Commission needs to strengthen the factual showing that RTOs and ISOs must make with respect to shortage pricing reforms. It states that each RTO's or ISO's compliance filing should include the following: (1) Market power analysis specifically addressing scarcity conditions, including pivotal supplier, market share, and the delivered price test; (2) an analysis of whether demand response successfully mitigates market power, including empirical evidence, such as critical loss analyses; (3) market power analyses addressing the ability of generation owners to withhold demand response; (4) a demonstration that the RTO has methods for mitigating market power that are effective during shortage periods, for any resources, demand or generation, that can affect prices; (5) an analysis of whether there is enough demand response available to respond under scarcity conditions, given reliance on demand response for capacity reserves and ancillary services; and (6) prepared statistics on past power shortages and expectations of future power shortages.

ii. Commission Determination

246. In this Final Rule, the Commission adopts the proposal to require each RTO or ISO to support its proposed reform in shortage pricing or its demonstration of the adequacy of its existing rules with adequate factual support. This factual record will allow the Commission to discharge its duty to ensure that any reform is necessary and narrowly tailored to address the circumstances in that region, and that it is designed to protect consumers against the exercise of market power. The Commission here adopts the six criteria proposed in the NOPR, as modified below, and will use these six criteria to consider whether the factual record compiled by the RTO or ISO meets the requirements adopted in this Final Rule.

247. After further review of the criteria identified in the NOPR, we revise the criteria. The RTO or ISO must describe how its proposal would:

- Improve reliability by reducing demand and increasing generation during periods of operating reserve shortage;
- Make it more worthwhile for customers to invest in demand response technologies;
- Encourage existing generation and demand resources to continue to be relied upon during an operating reserve shortage;
- Encourage entry of new generation and demand resources;
- Ensure that the principle of comparability in treatment of and compensation to all resources is not discarded during periods of operating reserve shortage; and

[336] Wal-Mart at 8.

[337] EPSA at 8.

[338] Comverge at 23.

[339] North Carolina Electric Membership at 12–13.

[340] *Id.* at 12.

[341] PG&E at 13.

• Ensure market power is mitigated and gaming behavior is deterred during periods of operating reserve shortages including, but not limited to, showing how demand resources discipline bidding behavior to competitive levels.

248. The criteria we adopt are not significantly different from the criteria proposed in the NOPR. Our intention in revising the criteria is to further clarify what we expect from an RTO's or ISO's compliance filing.[342] Under the revised criteria, we expect an RTO or ISO to explain how its market rules will reduce or avoid periods of operating reserve shortages as well as how its market rules will reliably reduce demand and increase generation during periods of operating reserve shortage. Nothing in this Final Rule dictates the particular market rules or mechanisms an RTO or ISO must adopt. For example, we do not require regions that have not adopted a capacity market to develop such markets. We are intentionally providing latitude to the RTOs and ISOs to work with their stakeholders to determine the appropriate mechanisms for their regions and then explain how those mechanisms meet the revised criteria.

249. Some commenters propose expanding or modifying the criteria. However, we conclude that the following suggestions are already either explicitly part of the required filing or are implicitly required. For example, North Carolina Electric Membership suggests a specific criterion that the Commission should adopt to protect consumers against the exercise of market power. Such a requirement, however, is already implicit in the required analysis of market power mitigation adopted here. Requiring that energy and ancillary services revenues be accounted for in the settlement of capacity market payments also is already an explicit requirement for existing capacity markets. Further, all RTOs and ISOs have established procedures by which market rule changes are developed, which generally include consultations with their stakeholders. We expect that RTOs and ISOs will work with their stakeholders to develop any new proposed rules and decline to make this an explicit criterion.

250. Similarly, the changes requested by PG&E are already addressed in the six criteria, as modified above. We note that an explicit requirement to evaluate the effect of a rule change on reliability is not needed. We are firmly of the opinion that the changes mandated in this Final Rule will increase system reliability by inducing additional response by demand- and supply-side resources and that RTO and ISO compliance will not result in a decrease in reliability. Second, requiring an explicit accounting of the costs of the program will not be included. We do not see the usefulness of this exercise. While there will be costs involved, the long-term benefits of maintaining grid reliability are evident.

251. As to when these pricing rules would go into effect, it is when the RTO or ISO has an operating reserve shortage. The reliability standards of the North American Electric Reliability Corporation, which have been approved by the Commission, or of other authorized reliability body, specify system operating reserve requirements, and these standards are well known to system operators such as RTOs and ISOs, as well as to the many stakeholders who helped develop them. The level of operating reserves required by the reliability standards depends on the characteristics of each system and cannot be correctly reduced to a single number that applies to every system, such as seven percent of peak load. Further, if we were to repeat the reliability standard definition here in our regulations, it would be cumbersome for reliability organizations to improve their definition of operating reserve requirements over time without also having to seek a change in our regulations. We find that this is the best definition of when these price reforms apply; we do not adopt a second, different definition, here, because having two definitions of operating reserve shortage would only cause confusion for system operators.

252. We decline to accept all other suggested criteria because they would represent a level of burden to the RTO or ISO that would exceed the benefit of doing the analysis.

253. We find that the criteria proposed in the NOPR, as modified above, are sufficient to show whether a region's proposed changes to its existing market rules meet the requirements of this rule, while protecting consumers from market power.

d. Phase-In of New Rules

254. In the NOPR, the Commission stated that each RTO or ISO may also consider a ''phase-in'' of its specific emergency pricing method over a period of years, giving three years as an example. This would serve to introduce customers gradually to pricing increases during an emergency and allow them to develop ways to reduce demand and avoid higher prices.[343]

i. Comments

255. Duke Energy states that while it prefers that any shortage pricing program start immediately, if a phase-in is deemed worthwhile, this phase-in should not be indefinite.[344] EEI also states that these rule changes may best be implemented through a phase-in, provided that it is not protracted.[345] It also notes that it is appropriate for the Commission to allow such a phase-in to be linked to key factors such as the deployment of advanced metering. Old Dominion supports a phase-in of emergency pricing.

256. FirstEnergy supports the Commission's proposed phase-in approach because it can allow the Market Monitor to evaluate the market reform, mindful of any unintended consequences including the exercise of market power and gaming.[346]

257. Industrial Consumers recommends that the Commission require a phase-in period of at least three to five years, together with benchmarks that measure the ability of specific market factors to protect consumers from the exercise of market power at the time of shortages. It urges that the shortage price levels only be allowed to increase in conjunction with and proportional to four benchmarks: (1) Measured and verified amount of new net incremental demand response resources entering the market; (2) net incremental reductions in congestion, whether through enhancement of generation or transmission resources, in the zones where such shortage pricing is implemented; (3) sustained increases in the volume of load hedged in long-term forward markets; and (4) development of credible forward price curves of power delivered at RTO and ISO hubs published in support of the third benchmark that are regularly relied upon by market participants.[347]

[342] For example, the third criterion in the NOPR sought an explanation of how the market rules encourage existing generation and demand resources needed during an operating reserve shortage to ''remain in business.'' Upon review, the Commission is concerned that this could have been read to require shortage pricing provisions that would subsidize or give preferences to resources to ensure they ''remain in business.'' Instead, our intention is for the RTO or ISO to explain how its shortage pricing proposal, together with existing market rules,encourages existing generation and demand resources to be available in an emergency. Similarly, the fifth criterion in the NOPR could have been read to limit comparable treatment and compensation for all resources to periods of operating reserve shortage. Because neither of these implications was our intention, we clarify the wording of these criteria.

[343] NOPR, FERC Stats. & Regs. ¶ 32,628 at P 128.

[344] Duke Energy at 11.

[345] EEI at 20.

[346] FirstEnergy at 12.

[347] Industrial Consumers at 19.

ii. Commission Determination

258. The Commission will allow an RTO or ISO to phase in any new pricing rules for a period of a few years, provided that this period is not protracted. Any phase-in period must be justified as part of the RTO's or ISO's overall proposal to change its pricing rules. No RTO or ISO is required to use a phase-in period, and we will not adopt by rule a requirement that any such phase-in be tied to certain benchmarks as Industrial Consumers and EEI propose. However, an RTO or ISO in consultation with its stakeholders, may propose to tie the phase-in period to certain benchmarks, and we will consider these in the compliance filing. We caution, however, that it should not choose to tie implementation to benchmarks that will not be met over a few years. This would not be consistent with our requirement that the phase-in period must not be protracted.

6. Reporting on Remaining Barriers to Comparable Treatment of Demand Response Resources

259. In the NOPR, the Commission recognized that further reforms may be necessary to eliminate barriers to demand response in the future. The Commission did not wish to delay the adoption of the specific reforms proposed in the NOPR while the Commission and the industry continue to study and consider other advances in this area. Rather, the proposed reforms were to proceed while the Commission and stakeholders studied what additional efforts were necessary and developed a record to support further reform.

260. The Commission directed staff to hold a technical conference to consider the following issues for demand response participation in the wholesale markets: (1) Whether there are barriers to comparable treatment of demand response that have not previously been identified, and what they are; (2) potential solutions to eliminate any potential barriers to comparable treatment of demand response; (3) appropriate compensation for demand response; and (4) the need for and the ability to standardize terms, practices, rules and procedures associated with demand response, among other things.[348]

261. In the NOPR, the Commission also proposed to require each RTO and ISO to assess and report on the barriers to comparable treatment of demand response resources that are within the Commission's jurisdiction, including those listed above. The RTOs and ISOs would be required to submit their findings and any proposed solutions, along with a timeline for implementation to address barriers, to the Commission within six months of the Final Rule's publication in the **Federal Register**. The Commission also proposed to require the Independent Market Monitor for each RTO or ISO to provide its views on this issue to the Commission. To ensure that minority views are adequately represented, the Commission proposed to require that the RTO or ISO identify any significant minority views in its filing.

262. The Commission sought comment on the proposed approach to identify and assess remaining barriers to comparable treatment of demand response as well as any particular issues or areas that should be addressed in the RTO and ISO reports.

a. Comments

263. A number of commenters indicate their support for the Commission's intention to continue to address barriers to demand response resources, and/or the Commission's proposal to require each RTO and ISO to report on the barriers they currently perceive.[349] Some offer suggestions for how the Commission should proceed toward this goal.

264. For example, APPA cautions the Commission, as it seeks to remove barriers to demand response resources, not to unintentionally endanger existing and planned demand response and energy efficiency programs at the retail level.[350] EnerNOC is encouraged by the Commission's objective to continue its oversight, to review and approve implementation of reforms for demand response programs and to consider future reforms.[351] However, it believes the Commission's continued involvement and active engagement may be necessary to eliminate barriers to demand response resources.

265. EEI agrees that the Commission should not delay the adoption of specific reforms for demand response while the Commission and industry stakeholders evaluate additional reforms in this area. However, EEI suggests that the Commission provide additional specification of the parameters of these studies, suggesting that the Commission clarify that such studies should not ignore existing work and should be conducted in a cost-effective manner. EEI also urges the Commission to have RTOs and ISOs study whether demand response is cost-effective and to quantify benefits.[352]

266. Regional entities report that they are already engaged in some of the issues the Commission described. With regard to future demand response reforms, the ISO/RTO Council says that it is working to develop standards for incorporating small demand response resources into organized markets, and that it is actively engaged with NAESB to standardize measurement and verification protocols.[353] These efforts, in combination with the Commission's technical conference, in which the ISO/RTO Council participated, should benefit future discussions on barriers, pricing, and standardization. The ISO/RTO Council looks forward to sharing the results of its standardization initiative.

267. Midwest ISO supports the Commission's approach to identifying additional demand response barriers and solutions, and states that many issues regarding barriers and solutions to demand response resources are already being addressed as part of the Midwest ISO's ongoing emergency demand response and long-term resource adequacy proceedings.[354] Through the rest of 2008, the Midwest ISO's Demand Response Working Group will facilitate many activities to further identify measures to advance demand response resources.

268. NYISO agrees that this Final Rule should not mark the end of the Commission's efforts in the demand response area and that further improvements and additional enhancements should be explored. NYISO has no objection to preparing the post-Final Rule report that the NOPR proposes.[355]

269. SPP notes that it is currently studying what further reforms are necessary to eliminate barriers to demand response in its organized markets. This process is done through its working groups and task forces as well as participating in groups such as the ISO/RTO Council.[356]

270. The California PUC believes that two important areas that could be improved are the evaluation of the cost-effectiveness of demand response and how it impacts load. The California PUC is working with stakeholders on both of these issues. The California PUC would

[348] NOPR. FERC Stats. & Regs. ¶ 32,628 at P 95. The technical conference was held on May 21, 2008. *See infra* note 12.

[349] *E.g.,* Exelon at 9; Pennsylvania PUC at 12; PG&E at 11; Public Interest Organizations at 8; Reliant at 6; and Steel Producers at 6.

[350] APPA at 51.

[351] EnerNOC at 22.

[352] EEI at 18.

[353] ISO/RTO Council at 8.

[354] Midwest ISO at 14–15.

[355] NYISO at 3.

[356] SPP at 6.

also like to see more effective load-shifting and the technology that allows for that to be encouraged to a greater degree.[357]

271. Old Dominion supports the Commission's proposal to continue discussions on demand response through RTO and ISO studies and suggests that RTOs and ISOs be required to identify all minority views and not just ''significant minority views'' as currently required by the NOPR. Old Dominion sees lack of telemetry, high implementation costs, institutional barriers related to cost recovery, insufficiently detailed business rules, and demand response gaming as impediments to demand response that should be discussed further.[358]

272. Old Dominion also suggests that each RTO and ISO should be directed to work with its stakeholders to develop by a specific date a prioritized list of barriers to demand response and a timeline for developing solutions to the same; that demand response should be considered in the transmission planning process in accordance with engineering-based transmission planning principles; and that implementation of demand response should be evolutionary in accordance with the sufficiency and certainty of business rules and availability of necessary measurement and verification infrastructure. Similarly, California DWR asks the Commission to require RTOs and ISOs to provide a listing of barriers identified by market participants, state or local regulators, the RTO or ISO market monitor, and the RTO or ISO itself; further, the RTOs and ISOs would provide information on their response to each barrier and let the Commission know if additional action is needed.[359]

273. Public Interest Organizations recommend that the Commission schedule a technical conference in each region to address both general and region-specific barriers.[360] Public Interest Organizations also recommend that RTOs and ISOs be required to: (1) Assess the potential of other demand-side resources in their control areas, including demand response, energy efficiency, and environmentally benign and efficient behind-the-meter distributed generation; (2) analyze and quantify all local and regional benefits as well as costs and risks of demand side resources available to address grid needs; and (3) assess and report on the longer-term impacts of demand resource participation on wholesale price levels and volatility, grid congestion, and system reliability.

b. Commission Determination

274. The Commission adopts the requirement that each RTO or ISO assess and report on any remaining barriers to comparable treatment of demand response resources that are within the Commission's jurisdiction and to submit its findings and any proposed solutions, along with a timeline for implementation, to the Commission within six months of the Final Rule's publication in the **Federal Register**. We further adopt the requirement that each RTO's or ISO's Independent Market Monitor must submit a report describing its views on these issues to the Commission. To ensure that minority views are adequately represented, the Commission requires that the RTO or ISO, in its report, identify any significant minority views; this does not, however, require reporting every opinion of every individual stakeholder.

275. The Commission appreciates the many thoughtful comments received in response to this proposal. RTOs and ISOs have a duty to remove unreasonable barriers to treating demand response resources comparably with other resources and the required report will help RTOs, ISOs, and the Commission to identify and address such barriers. The report should identify all known barriers, and provide an in-depth analysis of those that are practical to analyze in the compliance time frame given and a time frame for analyzing the remainder. As commenters have noted, this should include (but is not limited to) technical requirements as well as performance verification limitations. It need not contain, however, a formal cost-benefit analysis of each barrier and a proposal to overcome it. Public Interest Organizations suggest that RTOs and ISOs might hold regional conferences on this topic, and while we agree this may have merit, we leave to each region the means of developing its report.

276. Energy efficiency and distributed generation are valuable resources, as commenters point out; however, the scope of this rule is limited to removing barriers to comparable treatment of demandresponse resources in the organized markets. Hence, we will not require RTOs and ISOs to study these resources in the report we require. Nevertheless, nothing here precludes RTOs and ISOs from analyzing barriers to energy efficiency measures and distributed generation in their markets and proposing revisions to their tariffs that integrate these measures into their markets.

B. Long-Term Power Contracting in Organized Markets

277. In this section of the Final Rule, the Commission establishes a requirement that RTOs and ISOs dedicate a portion of their Web sites for market participants to post offers to buy or sell electric energy on a long-term basis. This requirement is designed to improve transparency in the contracting process to encourage long-term contracting for electric power. The Commission requires each RTO or ISO to submit a compliance filing describing actions the RTO or ISO has taken, or plans to take, to comply with the requirement and providing information on the bulletin board the RTO or ISO has chosen to implement.

1. Background

278. Long-term power contracts are an important element of a functioning electric power market. Forward power contracting allows buyers and sellers to hedge against the risk that prices may fluctuate in the future. Both buyers and sellers should be able to create portfolios of short-, intermediate-, and long-term power supplies to manage risk and meet customer demand. Long-term contracts can also improve price stability, mitigate the risk of market power abuse, and provide a platform for investment in new generation and transmission.

279. As the Commission noted in the NOPR, having an organized market in a region should facilitate long-term contracting by eliminating pancaked rates for long-distance power sales, eliminating loop flow problems within its footprint, and ensuring reliable transmission operation over a large area.[361] RTO and ISO transmission services also expand the size of the markets available to buyers and sellers of long-term power contracts, and provide independent and unified transmission scheduling and operation services over a large area.

280. The Commission has already taken action in other areas to facilitate long-term contracting. In Order No. 681, the Commission adopted a Final Rule on long-term transmission rights for organized market regions designed to assure availability of long-term transmission at a predictable cost.[362] The Commission then adopted transmission planning reforms in Order

[357] California PUC at 20.

[358] Old Dominion at 16–19.

[359] California DWR at 37.

[360] Public Interest Organizations at 8.

[361] NOPR, FERC Stats. & Regs. ¶ 32,628 at P 130.

[362] *Long-Term Firm Transmission Rights in Organized Electricity Markets,* Order No. 681, FERC Stats. & Regs. ¶ 31,226 (2006), *order on reh'g,* Order No. 681–A, 117 FERC ¶ 61,201 (2006).

No. 890 to provide an open and transparent process for wholesale entities and transmission providers to plan for the long-term needs of their customers. Interconnection rules for large, small and wind generators in Order Nos. 2003, 2006 and 661 have provided a uniform and transparent interconnection process and provided for interconnection with network integration service to facilitate long-term reliance on new generation.[363] The Commission has also reformed capacity markets in several regions to shift reliance from short-term purchases to forward markets held sufficiently in advance of delivery (*e.g.*, three years) to be more consistent with the time necessary to construct new generation.[364]

281. The Commission did not find that there is a fundamental problem with long-term contracting for electric power, either inside or outside of organized markets. The interest among buyers and sellers in engaging in long-term contracting fluctuates depending upon the balance of resources and demand in the market for power. Interest among buyers for long-term arrangements was low when excess generation was readily available. Although demand for long-term contracting by buyers has increased as reserve margins have shrunk, buyers are still able to enter into long-term contracts. These contracts may be at higher prices than in the past, but this is a result of market factors, such as changes in fuel prices and shifting supply and demand. Finding no fundamental problem preventing parties from contracting on a long-term basis, the Commission proposed to limit its action in this proceeding to improving transparency in long-term contracting in organized markets.

282. In the NOPR, the Commission stated that further transparency in long-term electric energy markets would facilitate efforts by both sellers and buyers to include long-term contracts in their energy portfolios. This is especially true for market participants that may not be aware of the full range of contract options available to them, including the full range of potential contract counterparties. While the market has the most important role to play in disseminating information, an RTO or ISO can also promote greater transparency and liquidity in long-term power markets,[365] and thus help reduce possible over-reliance on spot markets. In the NOPR, the Commission proposed that regional organizations play a supporting role in encouraging voluntary contracting by providing an online forum in which potential buyers and sellers may exchange information.[366]

2. Commission Proposal

283. In the NOPR, the Commission proposed to require that RTOs and ISOs dedicate a portion of their Web sites for market participants to post offers to buy or sell electric energy on a long-term basis.[367] The Commission stated that the proposal for an RTO or ISO Web site ''bulletin board'' for posting long-term offers to sell or buy electric energy is designed to facilitate the long-term contracting process by increasing the transparency of the availability of potential sellers and buyers for market participants. The Commission did not propose to mandate the specific type of bulletin board that each RTO and ISO must post, but proposed to require each to work with its stakeholders to design a solution that works for its market participants.[368] The Commission also encouraged RTOs and ISOs to work with stakeholders to facilitate long-term power contracting.

284. The Commission proposed to require RTOs and ISOs to make a compliance filing within six months of the date of publication of the Final Rule in the **Federal Register**. This filing should explain the actions the RTO or ISO has taken or plans to take to comply with the long-term contracts bulletin board requirement and provide information on the bulletin board the RTO or ISO has chosen to implement.[369]

285. The Commission also sought public comment on a number of questions related to its proposal, including comment on minimum necessary features and processes for the Web page and the proposal that the RTO or ISO should not be responsible for the content of the offers on its bulletin board. Further, the Commission solicited comment on provisions for the disclaimer of liability by the RTO or ISO and by market participants.[370]

3. Comments

286. A majority of commenters either support[371] or do not object[372] to the Commission's proposal to require RTOs and ISOs to implement bulletin boards to facilitate long-term power contracts. Most commenters note that the Commission should not impose conditions on the format of the bulletin board, but should instead leave the creation to RTOs and ISOs in conjunction with their stakeholders.[373] Some commenters also state that the Commission should act to ensure that RTOs or ISOs should not be held liable for postings on their bulletin boards.[374] For instance, NYISO states that the Commission should allow posted disclaimers against liability by the RTOs on their bulletin board Web sites. Midwest ISO also requests that the Commission provide assurance that RTOs and ISOs will not be exposed to antitrust liability for providing a contracting forum. Finally, commenters generally believe that the cost of a bulletin board will be low for RTOs and ISOs.[375]

287. Those commenters who do not support the Commission's proposal generally argue that a bulletin board would be an unnecessary requirement. Both CAISO and California Munis state that CAISO is busy with other projects, and that a bulletin board would be low

[363] *Standardization of Generator Interconnection Agreements and Procedures,* Order No. 2003, FERC Stats. & Regs. ¶ 31,146 (2003), *order on reh'g,* Order No. 2003–A, FERC Stats. & Regs. ¶ 31,160, *order on reh'g,* Order No. 2003–B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g*, Order No. 2003–C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC,* 475 F.3d 1277 (DC Cir. 2007); *Standardization of Small Generator Interconnection Agreements and Procedures,* Order No. 2006, FERC Stats. & Regs. ¶ 31,180, *order on reh'g,* Order No. 2006–A, FERC Stats. & Regs. ¶ 31,196 (2005), *order granting clarification,* Order No. 2006–B, FERC Stats. & Regs. ¶ 31,221 (2006), *appeal pending sub nom. Consolidated Edison Co. of New York, Inc., et al. v. FERC* Docket No. 06–1018, *et al.; Interconnection for Wind Energy,* Order No. 661, FERC Stats. & Regs. ¶ 31,186, *order on reh'g,* Order No. 661–A, FERC Stats. & Regs. ¶ 31,198 (2005).

[364] *Devon Power, LLC,* 115 FERC ¶ 61,340, *order on reh'g,* 117 FERC ¶ 61,133 (2006), *aff'd in part and rev'd in part sub nom. Maine Pub. Utils. Comm'n v. FERC,* 520 F.3d 464 (DC 2008); *PJM Interconnection, LLC,* 117 FERC ¶ 61,331 (2006).

[365] Transcript of Conference at 117, Conference on Competition in Wholesale Power Markets, Docket No. AD07–7–000 (May 8, 2007).

[366] NOPR, FERC Stats. & Regs. ¶ 32,628 at P 137.

[367] *Id.* P 155.

[368] *Id.* P 156–57.

[369] *Id.* P 158.

[370] *Id.* P 159.

[371] *See, e.g.*, APPA at 72; DC Energy at 8; EEI at 4; Exelon at 15; LPPC at 4; Midwest ISO at 18; NEPOOL at 19–20; New York PSC at 4; NIPSCO at 15; NRECA at 47; NSTAR at 5; NYISO at 11; OMS at 7; Pennsylvania PUC at 16; Steel Producers at 10; and Xcel at 11. NIPSCO notes that its support is contingent on the bulletin boards having common elements or generic features across all organized markets, and the boards not burdening the RTO.

[372] *See, e.g.*, Ameren at 29–30; EPSA at 12; FirstEnergy at 12; Indianapolis P&L at 4; Industrial Coalitions at 32–35; Industrial Customers at 21; North Carolina Electric Membership at 13–15; Ohio PUC at 16; Old Dominion at 19–20; OMS at 7–8; PJM at 2; and TAPS at 3.

[373] *See, e.g.*, Ameren at 30; APPA at 72; CAISO at 19; DC Energy at 9; EEI at 20; EPSA at 12; Exelon at 15; NEPOOL Participants at 19–20; North Carolina Electric Membership at 13–15; NYISO at 12; Old Dominion at 19; PJM at 2; and Xcel at 11.

[374] *See, e.g.*, Ameren at 30; CAISO at 19; Exelon at 15; Midwest ISO at 18; NRECA at 48; NYISO at 12; Ohio PUC at 16; Reliant at 11; and SPP at 7.

[375] *See, e.g.*, Ameren at 30; CAISO at 19; EEI at 20; Midwest ISO at 18; and PJM at 2.

on the list of necessary items.[376] CAISO is concerned over the proposed deadline for implementation, and argues that any deadline should be after the launch of its MRTU. It also believes that regions should be allowed to be flexible on whether to develop bulletin boards and how many features the board should have. California PUC agrees that a federal requirement is unnecessary, and that the Commission should authorize, rather than require, action on bulletin boards. SPP also advocates that the Commission should make its proposal a voluntary one, rather than a regulatory requirement. Some commenters, such as EPSA, NIPSCO, Ohio PUC, Steel Producers and North Carolina Electric Membership, who do not object to the proposal, indicate that they do not believe that bulletin boards will have a significant effect on long-term contracting. FirstEnergy indicates that, although it does not object to the proposal, it believes that sufficient information on the market is already provided by private companies and thus RTOs do not need to be further involved. Reliant states that bulletin boards would not resolve any of the current impediments to long-term contracts, as there are already sufficient mechanisms in the market to provide information for buyers and sellers.

288. Commenters' suggestions for implementing the bulletin board requirement include: (1) A requirement that posts should not be viewed as binding offers but rather as voluntary postings;[377] (2) a suggestion that price information not be required in postings to the bulletin board;[378] (3) a requirement that any significant costs of the bulletin board should be borne by its users;[379] (4) an expansion of the data posted to include percentage and volume of bilaterally contracted energy;[380] (5) an expansion of the bulletin board to cover other products such as ancillary services;[381] (6) a requirement that RTOs and ISOs collect and disseminate information on the usefulness of bulletin boards;[382] (7) a requirement that bulletin boards provide common elements or generic features across all organized markets; and (8) a mandated cost analysis of the bulletin board by the RTO/ISO.[383]

289. Midwest ISO states that it already has an early version of a portal in place on its Web site, and that it would involve minimal costs to create a bulletin board for long-term contracts. Midwest ISO recommends that, as an intermediate measure prior to the implementation of a web portal, contracting parties provide essential terms—including price, quantity, term, and receipt and delivery points—to the RTO or ISO and fill out a form indicating the data they wish to be kept confidential.[384]

290. NEPOOL Participants raises some legal and other issues for the Commission to consider when developing its bulletin board requirement. These include: (1) Ensuring that postings are not considered binding offers under the Uniform Commercial Code; (2) not allowing the board to substitute for regulated markets; and (3) ensuring that the same antitrust and market manipulation rules that apply to market behavior also apply to activity on the bulletin board.[385]

291. NSTAR states that it is concerned that data from the bulletin board containing prices for long-term power could influence market prices. Accordingly, it asks the Commission to consider additional requirements to ensure that information posted on the boards is from a representative cross-section of market participants, to reduce the impact of the bulletin board on market prices.[386]

292. Industrial Customers state that the Commission should define ''long-term'' as substantially more than one year and consistent with building cycles of new or expanded production capacity. They argue that any entity making construction decisions on new facilities needs knowledge of prices going forward to make investment decisions.

293. Many commenters argue that the Commission did not address in its proposed regulations the actual causes behind the lack of long-term contracts in the market. Several commenters point to the structure of markets within the RTO system, which they assert causes an over-reliance on spot markets and a lack of long-term contracts. They say this structure includes LMP pricing, which provides a disincentive for producers to contract for lower prices on a long-term basis. For instance, APPA points to studies including one performed by Synapse Energy Economics, Inc., indicating that there are structural barriers to long-term contracting in the organized markets. Other commenters point to the need for stability of market rules and uncertainty about climate change policies as key factors in keeping parties from contracting on a long-term basis.[387] Reliant indicates that the issue is actually a difference in perceptions between buyers and sellers about the appropriate price of energy and the allocation of risk between the buyers and sellers. NRECA points to several other issues that affect long-term contracting in organized markets, including price volatility, price risk, delivery risk and resource availability. Ohio PUC echoes some of these concerns, noting that risks with recovering capital costs are preventing new generation from being built in states with retail access, and that unpredictable congestion charges and uncertainty surrounding the working of RTO markets are also hurting long-term contracting.

294. Commenters suggest several actions that the Commission should take to remedy these broader concerns. Commenters, including NRECA, Industrial Coalitions and Blue Ridge, ask the Commission to do its own investigation of the bilateral contracting process and over-reliance on the spot markets. North Carolina Electric Membership notes that a requirement of ''full support'' from stakeholders for more complex RTO or ISO market design changes may increase the stability and predictability to these markets, which may facilitate longer term contracting. Constellation states that the Commission should promote rules to encourage contracting across seams and take measures to provide sufficient transparency, information and regulatory certainty to manage transactional risk. Cogeneration Parties argue that the Commission should take action to improve price transparency in organized markets, and assist in the creation of standard products and contracting terms for long-term contracting. SoCal Edison-SDG&E argue that local measures to improve regulatory stability would do more to support long-term contracting than a Commission rulemaking. They point to the California PUC proceeding to develop long- term resource adequacy requirements as one such local measure, and argue that the Commission should focus on the merits of individual RTO or ISO proposals rather than a nationwide rulemaking. Finally, TAPS notes that an important way to facilitate long-term contracts is to ensure that load-serving entities can access necessary transmission resources.

[376] CAISO at 19; California Munis at 18.

[377] Ameren at 30–31.

[378] Xcel at 11–12.

[379] CAISO at 18–20; EEI at 21.

[380] Industrial Coalitions at 33–35.

[381] NEPOOL Participants at 18–21.

[382] Pennsylvania PUC at 16.

[383] Old Dominion at 19–20.

[384] Midwest ISO at 19.

[385] NEPOOL Participants at 20.

[386] NSTAR at 5–6.

[387] *See, e.g.*, SoCal Edison-SDG&E at 4; EPSA at 11–12.

However, TAPS is concerned by recent orders indicating that the Commission may relieve RTOs of certain responsibilities they have under Order No. 681 [388] to plan for resource adequacy and maintain simultaneous feasibility of financial rights. It argues that if the Commission is serious about facilitating long-term contracts, it should require RTOs and ISOs to live up to the letter and spirit of Order No. 681.

295. Several commenters call on the Commission to hold a technical conference and require a stakeholder process to address the lack of certain financial hedging instruments so as to reduce price uncertainty for long-term contracts. For instance, both California Munis and SMUD argue that buyers in CAISO lack options-type instruments for hedging LMP congestion costs and lack a means to hedge against the cost of marginal losses. Providing these hedges, they argue, would encourage long term contracting.

296. Commenters raise a variety of other issues related to long-term contracting. Midwest Energy states that it is concerned about the impact of a Day-2 market on long-term contracts, and appreciates that the Commission is not imposing Day-2 market structures on all RTOs and ISOs.

297. California PUC notes that it is presently addressing long-term contracting within its procurement proceedings. For instance, under the California PUC's Resource Adequacy program, all California PUC jurisdictional LSEs are required to procure necessary capacity on a year-ahead basis. Additionally, California PUC requires LSEs to identify longer-term needs and procure energy necessary to meet those needs through a request for offer process that includes both long and short-term contracts. California PUC questions the Commission's legal basis for intervening in long-term contracting, stating that the NOPR does not explain the statutory authority for the Commission's proposed involvement in long-term energy supply contracts between generators and LSEs. It notes that FPA section 215 does not authorize the Commission to set or enforce compliance with standards for resource adequacy, and that EPAct 2005 ''expressly retains state authority to assure the reliability of the energy supply within their jurisdictions.'' [389] It seeks assurance that the Commission does not intend to exercise jurisdiction over the wholesale energy market as a method of indirectly modifying California's reliability processes.

298. Both New York PSC and NARUC state that the Commission should not attempt to standardize long-term contracts. NARUC argues that standardization would hurt state policy objectives such as integrated resource planning, renewable portfolio standards and resource adequacy requirements. New York PSC notes that any standardized forward products should be developed through the RTO or ISO stakeholder process.

299. PJM notes that it held a stakeholder forum in January 2008 to discuss greater opportunities for long-term contracting in PJM. This forum resulted in identification of areas for future action, which included: (1) Education of policy makers and the public on the need for new infrastructure; (2) improved coordination of various agency and regulatory decision makers on market issues; (3) predictability and stability in regulatory rules; (4) improvements in siting for transmission and generation; (5) ways of steering revenue to increase the amount of new generation; (6) more effective demand response programs to increase market elasticity and reduce potential for exercise of market power; (7) a portfolio of purchases to vary prices and terms for state-sanctioned auctions; (8) further examination of existing market models such as the AF&PA proposal; and (9) additional credit support for parties interested in long- term contracting, through methods such as syndication of credit risk and government guarantees.[390]

300. Finally, APPA notes that although it appreciates the effort that PJM put into holding its long-term contracting forums, APPA understands that no concrete proposals for improving long-term contracting have emerged as a result of the forums. Accordingly, APPA cannot endorse the idea of similar efforts by other RTOs as suggested by the Commission in the NOPR, given the scarce resources of RTOs and market participants. Instead, APPA supports preparation of an in-depth analysis of long-term contracting practices for each RTO region by the RTO's MMU, given the MMU's knowledge of conditions ''on the ground.'' This analysis should consider impediments to long-term contracting and measures that could be taken to support long-term contracts of sufficient length to support the building of new generation.

4. *Commission Determination*

301. We will require each RTO and ISO to dedicate a portion of its Web site for market participants to post offers to buy or sell power on a long-term basis. The Commission defines ''long-term'' as one year or more for the purposes of this rule, but RTOs and ISOs may include offers for contracts of less than a year on their Web sites as well. The Web site should allow both buyers and sellers to post and read offers for long-term power transactions. A majority of commenters support this proposal, and we conclude that greater transparency from a bulletin board for long-term power sales will benefit long-term contracting.

302. We are convinced by the comments that the costs involved for creation and upkeep of the bulletin board are likely to be minimal and are justified by the increased transparency for potential sellers and buyers, and should thus be recovered similarly to other Web site costs. A few commenters suggest that bulletin board costs should be borne by its users. If an RTO or ISO in consultation with its stakeholders believes that costs of the bulletin board will be significant, it may explain in its compliance filing how it plans to recover the costs, including whether it plans to charge users of the bulletin board.

303. The Commission is not mandating any specific form for the Web site beyond the requirements above. We will instead leave the implementation to RTOs and ISOs and their stakeholders. This discretion includes decisions over the type and amount of data to be posted by participants, whether participants must include a proposed price in their posting, as well as password and security requirements. Commenters who have specific suggestions about the form and content of the Web site bulletin boards, or concerns over cost issues, should raise these suggestions with their RTOs or ISOs through the stakeholder process. The compliance filing of each RTO or ISO will provide an opportunity for interested persons to comment to the Commission on each RTO's and ISO's method of compliance, such as the legal and other concerns raised by NEPOOL Participants and others. The Commission does not find it necessary to make a generic determination about these concerns.

304. The Commission agrees with commenters that RTOs and ISOs should not be held liable for the postings of contracting parties.[391] Significant

[388] *Long-Term Firm Transmission Rights in Organized Electricity Markets*, Order No. 681, FERC Stats. & Regs. ¶ 31,226 (2006), *order on reh'g*, Order No. 681–A, 117 FERC ¶ 61,201 (2006).

[389] California PUC at 28 (citing 16 U.S.C. 824o(i)).

[390] PJM at 3–4.

[391] The Commission does not see why having such a bulletin board should necessarily expose an RTO or ISO to antitrust liability, as suggested by

liability protection for message board operators is already provided under federal law by the safe harbor provisions of the Communications Decency Act.[392] We anticipate that these provisions will apply to RTOs and ISOs. Consistent with comments received, however, we encourage RTOs and ISOs to post a disclaimer on their Web sites indicating that they are not responsible for the content posted by users, and outlining the terms and conditions under which users may post offers to buy or sell under long-term agreements.

305. In response to comments from NSTAR, the Commission is not persuaded to forego the advantages of posting long-term contract term proposals just because an entity might attempt to use the bulletin board inappropriately. Further, we see no reason to mandate in this proceeding specific limits on types of posting on RTO or ISO Web sites. However, any attempt by posters to use this new feature to manipulate the market price or market price indices will be subject to Commission penalty or referral to other agencies having jurisdiction.[393]

306. In response to the concerns raised by California PUC, New York PSC and NARUC, the Commission notes that it is not taking any action at this time to standardize long-term contracts, nor does the Commission intend this bulletin board posting requirement to be a reliability standard, to set a resource adequacy requirement, or to infringe on state regulatory jurisdiction.

307. We anticipate that this requirement will enhance transparency and help foster long-term contracting without standardizing RTO and ISO approaches or intruding unduly into matters more appropriate for markets and the private sector. The comments provide strong support for the bulletin board proposal, and do not persuade us that there is any reason to delay implementation of this requirement, despite CAISO's request that we postpone it until after MRTU is complete. Some of the other requirements commenters propose would require more standardization and set requirements that are better left to the free market and to the private sector. We do not wish to delay or undermine this process by imposing too many requirements. Therefore, the Commission will not require in this rulemaking other actions related to long-term contracting recommended by some commenters.

308. As discussed in the NOPR, many of the broader issues commenters raise herein regarding the structure and functionality of organized markets are beyond the scope of this proceeding and would require further development to be ripe for inclusion in a rulemaking.[394] The Commission further explored many of the issues during the recent technical conference held to discuss the proposals of American Forest and Portland Cement Association, *et al.* [395] The Commission continues to review the information it received at the technical conference for possible action.

309. RTOs and ISOs are required to make a compliance filing within six months of the date of publication of this rule in the **Federal Register**. The filing should explain the actions the RTO or ISO has taken or plans to take to comply with the long-term contracts bulletin board requirement and provide information on the bulletin board the RTO or ISO has chosen to implement. The Commission appreciates concerns of commenters that RTOs and ISOs, such as CAISO, have market reforms in progress, and these entities may take into account the timetable of reforms in progress when developing their compliance plans. We find that the compliance period of six months is an adequate time to make any necessary adjustments to planned reforms and explain them in the compliance filings.

C. Market-Monitoring Policies

310. In this section of the Final Rule, the Commission makes reforms to enhance the market monitoring function and thereby improve the performance and transparency of organized RTO and ISO markets. The two principal areas addressed are the independence and functions of the MMU, and information sharing. The Final Rule requires tariff provisions that will remove the MMU from the direct supervision of RTO or ISO management, and requires, in most instances, that the MMU report directly to the RTO or ISO board of directors.

311. The Final Rule also imposes obligations on the RTOs and ISOs to provide the MMU with adequate tools with which to carry out its duties. The Final Rule broadens the reporting duties of the MMU, clarifies that it is to refer to Commission staff any instances of misconduct by the RTO or ISO, as well as by a market participant, and expands the MMU's referral obligations to include perceived market design flaws as well as instances of tariff or rule violations.

312. In the area of mitigation, the Final Rule separates the duties of internal and external MMUs in the case of RTOs and ISOs that employ a hybrid structure, and provides that for non-hybrid MMUs, mitigation by the MMU should center on retrospective mitigation and the calculation of inputs required for the RTO or ISO to conduct prospective mitigation. Given the critical nature of MMU duties, the Final Rule requires RTOs and ISOs to include in their tariffs ethical standards for their MMUs. The Final Rule also requires RTOs and ISOs to consolidate all of their MMU provisions into one section of their tariffs.

313. In the area of information sharing, the Final Rule expands the category of recipients for the information gathered by the MMU, and broadens MMU reporting requirements. It also expands the abilities of state commissions to obtain additional and more tailored information from MMUs, while preserving confidentiality protections. The Final Rule also reduces the lag time for the release of offer and bid data.

1. Background

314. Since the inception of organized energy markets, the Commission has required RTOs and ISOs to employ a market monitoring function. MMUs have consistently played a vital role in reporting on the state of the markets and ferreting out wrongdoing by market participants. In May of 2005, the Commission issued a Policy Statement on Market Monitoring Units,[396] which set forth the tasks MMUs were expected to perform, and established a procedure for MMU referral of suspected violations to Commission staff.

315. Concerns raised by interested entities in the context of individual RTOs and ISOs led the Commission to undertake a generic examination of MMUs at a technical conference held on April 5, 2007.[397] At that conference, the

Midwest ISO. However, the Commission suggests that RTOs and ISOs explain any such concerns in their compliance filings.

[392] 47 U.S.C. 230(c)(1) (''No provider or user of an interactive computer service shall be treated as the publisher or speaker of any information provided by another information content provider.''). *See, e.g., Universal Commun. Sys. v. Lycos, Inc.*, 478 F.3d 413 (1st Cir. 2007) (dismissing a suit against a content provider for liability for posts on a community message board based on the safe harbor provisions of the Communications Decency Act).

[393] *See Price Discovery in Natural Gas and Electric Markets*, 104 FERC ¶ 61,121, at P 38 (2003).

[394] NOPR, FERC Stats. & Regs. ¶ 32,628 at P 153, 161.

[395] Supplemental Notice of Technical Conference, Capacity Markets in Regions with Organized Electric Markets, Docket No. AD08–4–000 (April 25, 2008).

[396] *Market Monitoring Units in Regional Transmission Organizations and Independent System Operators*, 111 FERC ¶ 61,267 (2005) (Policy Statement).

[397] Notice and Agenda for the Conference, Review of Market Monitoring Policies, Docket No. AD07–8–000 (Mar. 30, 2007).

issues receiving the bulk of the attention centered on the perceived need for, and suggested methods of achieving, independence on the part of MMUs so they can perform their assigned functions, and the content and proper recipients of the MMUs' market data and analysis. These issues accorded with the Commission's perception of the areas within the market monitoring function that needed review and strengthening.

316. In the ANOPR and the NOPR, the Commission proposed numerous reforms designed to strengthen MMU independence and broaden information sharing by the MMUs. Many of these proposed reforms have been carried forward to this Final Rule, while others have been modified or, in a few cases, eliminated, based on the comments received from interested entities. The resulting reforms set forth in the Final Rule provide the MMUs with enhanced ability to monitor the markets and provide interested entities with the ability to receive additional market information, thereby improving market performance and transparency.

2. Independence and Function

317. In the NOPR, the Commission acknowledged the importance of MMU independence, and stated that there are several means by which to balance independence and accountability. The Commission proposed a balanced and flexible approach that included oversight protection, tariff safeguards and tools, the elimination of conflicts of interest, and certain changes in the functions MMUs are expected to perform. The Commission solicited comments on the proposed changes.

a. Structure and Tools

i. Commission Proposal

318. The Commission proposed that each RTO and ISO decide for itself, through its appropriate stakeholder process, whether it will have an external, internal or hybrid MMU structure. The Commission declined to remove MMUs from oversight by their RTOs and ISOs, as the MMU's principal duties involve monitoring RTO and ISO markets and advising the RTO or ISO on market performance. The Commission noted that the fact that MMUs also have reporting obligations to outside parties does not change their relationship with the RTOs and ISOs, which are, by Commission policy, required to maintain a market monitoring function.

319. The Commission further proposed that each RTO or ISO include in its tariff a provision imposing upon itself the obligation to provide its MMU with access to market data, resources, and personnel sufficient to enable the MMU to carry out its functions. The Commission noted that the RTO or ISO should, in addition, be mindful of these obligations in developing its market monitoring budget. Furthermore, to ensure independence of the MMU and its analyses, the RTO or ISO tariff should specifically provide that the MMU shall have access to the RTO's or ISO's database of market information. The tariff should also specify that any data created by the MMUs, including reconfiguring of the RTO or ISO data, be kept within the MMU's exclusive control.

ii. Comments

320. Constellation states the Commission's proposals are on the right track.[398] Dominion Resources and EPSA agree.[399] Potomac Economics states that the Commission's proposals appear generally to be consistent with the nature of the existing relationship between Potomac Economics and the Midwest ISO, which allows Potomac Economics sufficient independence to monitor both the market participants and the market operator. Further, Potomac Economics, the Midwest ISO and state regulators all see the current structure as providing needed independence while ensuring responsiveness to regional needs.[400]

321. Most commenters agree that the Commission should allow each RTO or ISO to determine its own structural relationship with its MMU through its stakeholder process.[401]

322. PG&E endorses the use of hybrid MMU structures (internal MMU reporting to RTO or ISO management and external MMU reporting to the RTO or ISO board), but emphasizes the RTO or ISO must meet the following conditions: (1) both MMUs must have access to all data and the ability to request data and information from market participants if needed to perform market analysis functions; (2) both MMUs should cooperate in assessing any issues regarding the markets, including sharing identification of market problems developed by either MMU, and sharing complaints or requests for investigation raised by any market participant to either MMU; and (3) both MMUs must have adequate resources and authority to refer matters to the Commission and its Office of Enforcement.[402]

323. Industrial Consumers believe the Commission should mandate the hybrid structure for all RTOs or ISOs, reasoning that the external MMU, if not dependent for its main salary or contract on services performed for the RTO or ISO, is presumed to be independent. It cites the California ISO's Market Surveillance Committee as a successful example.[403]

324. Most commenters agree that the Commission should require each RTO or ISO to include a tariff provision imposing on itself the obligation to provide its MMU with access to market data, resources and personnel sufficient to enable the MMU to carry out its functions. They also agree that to ensure the MMU's independence, the MMU should have access to the RTO's or ISO's database of market information. Further they agree that any data created by the MMUs should be kept within the exclusive control of the MMU.[404] Three commenters state that the Commission should consider the provisions of a recent settlement agreement it approved as constituting "best practices."[405] Further, APPA states that the Commission must specifically incorporate all of the MMU-related provisions of the PJM MMU Settlement Order into the Final Rule because the provisions now appear in a settlement agreement and have no precedential value.[406] CAISO asks the Commission to clarify that "exclusive control" means that an MMU has the right to keep data it creates within its control, but has the option to share such data. CAISO states it appears this right is implicit in the Commission's proposal, but the Commission should make it explicit.[407] Reliant suggests that the Commission should clarify that MMUs should have full access to RTO or ISO operational information to determine if RTO operational decisions are negatively impacting appropriate price signals.[408]

325. APPA and Ohio PUC state that MMU offices should be at the RTO or ISO site.[409] APPA, California PUC and TAPS believe that the Commission should require a tariff provision

[398] Constellation at 16.

[399] Dominion Resources at 8; EPSA at 12–13.

[400] Potomac Economics at 7–8.

[401] Ameren, California PUC, EEI, EPSA, FirstEnergy, and North Carolina Electric Membership.

[402] PG&E at 14–15.

[403] Industrial Consumers at 21.

[404] Ameren, APPA, Exelon, California Munis, CAISO, EPSA, FirstEnergy, Industrial Consumers, ISO New England, Midwest Energy, Midwest ISO, Old Dominion, Pennsylvania PUC, PJM Power Providers, Reliant, and SPP.

[405] APPA, Exelon and Pennsylvania PUC (citing *Allegheny Electric Cooperative, Inc., et al. v. PJM Interconnection, LLC,* 122 FERC ¶ 61,257 (2008) (PJM MMU Settlement Order)).

[406] APPA at 6–7, 78–80.

[407] CAISO at 12–13.

[408] Reliant at 13.

[409] APPA at 80–81; Ohio PUC at 23.

directing an MMU to report to the Commission any concerns it has with inadequate access to market data, resources, or personnel.

iii. Commission Determination

326. The Commission adopts the NOPR proposal that each RTO or ISO should decide for itself the structural relationship it desires for its MMU. Regional variances and preferences in this regard should be respected, and we decline to mandate any one structure for the MMU function.

327. We therefore reject the suggestion from Industrial Consumers that we mandate a hybrid-type MMU structure consisting of both an internal and an external monitor. While the hybrid structure can provide many benefits, we have not observed that any RTOs or ISOs with purely internal or external MMUs suffer deficiencies in performance as a result. Nor would a hybrid MMU necessarily be more or less independent than an internal or an external MMU: Hybrid MMUs receive funding from their RTOs or ISOs, just as do internal and external MMUs. Neither Industrial Consumers nor other commenters have presented examples of dysfunctional MMUs, much less a dysfunction that can be attributed to a particular organizational structure.

328. We also adopt the NOPR proposal that RTOs and ISOs include provisions in their tariffs: (1) Obliging themselves to provide their MMUs with access to market data, resources and personnel sufficient to enable them to carry out their functions; (2) granting MMUs full access to the RTO or ISO database; and (3) granting MMUs exclusive control over any MMU-created data. Without the proper tools, it would be impossible for MMUs to perform their functions.

329. We clarify, in accordance with CAISO's request, that MMUs may share data under their exclusive control, subject to pertinent confidentiality provisions. We also clarify, as requested by Reliant, that access to the RTO or ISO database includes access to RTO or ISO operational information.

330. We decline to adopt as ''best practices'' the provisions of the recent settlement agreement entered into by PJM and a number of interested parties concerning the structure, function and independence of PJM's MMU (PJM/MMU Settlement Agreement).[410] The provisions of that agreement were specific to one RTO, and represented a negotiated balancing of interests. It would be inappropriate to impose the specifics of that settlement on all other RTOs and ISOs, and especially to do so without notice and the opportunity to comment. However, we observe that the PJM/MMU Settlement Agreement is in accord with our determinations in this Final Rule regarding the appropriate MMU structure and tools.[411]

331. We decline to require that MMU offices be at the RTO or ISO site. While such a location may well have its advantages, it is also possible that, in this age of electronic communications, other forms of access may be satisfactory. In any event, this is a level of detail that is best worked out on a case-by-case basis.

332. We find it unnecessary to require inclusion of a tariff provision directing the MMU to report to the Commission any concerns it may have with inadequate access to market data, resources or personnel. As we noted in the NOPR, there are already adequate mechanisms for the MMU to bring any noncompliance in this regard to the Commission's attention.[412]

b. Oversight

i. Commission Proposal

333. The Commission proposed in the NOPR that the MMU, for purposes of supervision over its market monitoring functions, should report to the RTO or ISO board rather than to management. The Commission further proposed that management representatives on the board be excluded from this oversight function. However, the Commission noted that, if RTOs and ISOs deem it appropriate, they may have the MMU report to management for administrative purposes, such as pension management, payroll and the like. The Commission also proposed that, if an RTO or ISO has a hybrid MMU structure with two market monitoring bodies, an internal and an external one, the RTO or ISO may have the internal market monitor report to management with respect to both its market monitoring and administrative functions, and the external market monitor report to the board. The Commission rejected the suggestion that the MMU should report to a body outside of the RTO or ISO structure.

334. The Commission also declined to impose a blanket requirement that major changes in MMU status, such as termination of employment, be made subject to Commission review. Such requirements are included in the contractual arrangements of certain RTOs or ISOs, but the Commission rejected imposing a ''one size fits all'' requirement on the remaining RTOs or ISOs absent their consent.

ii. Comments

335. Commenters addressing the subject generally agreed that an MMU should report to an RTO or ISO board rather than to management.[413] APPA cautions that an RTO or ISO board must be prepared to take appropriate oversight action when an MMU reports to it.[414] FTC states that given the importance of MMU independence and recent concerns in this area, the Commission may wish to earmark this topic for periodic review, including an analysis of best practices both in the United States and abroad.[415]

336. With respect to the proposed exception for hybrid MMUs, five commenters support the proposal.[416] For hybrids, most commenters agree that the internal monitor may report to management if the external monitor reports to the board. Another commenter, DC Energy, opposes this proposal, arguing that all market monitors should report to the board to ensure independence. TAPS states that the mix of duties between internal and external market monitors varies from region to region, with the external market monitor being ''weak'' in some cases and the internal market monitor performing the essential duties. TAPS proposes that the Commission require that the external market monitor be responsible for the MMU duties spelled out in the NOPR (*e.g.*, identifying ineffective market rules, reviewing the performance of the market, and making referrals to the Commission).

337. On the issue of reporting to a body other than the RTO or ISO, Ohio PUC believes that an external MMU should report to the RTO's or ISO's board of directors only as an interim step. It states that the Commission's long-term goal should be total MMU independence, with the MMUs reporting as consultants to a Federal-State Joint Board on Market Monitor Oversight or to some other form of a joint-board construct, manned by a Commissioner and state commissioner

[410] *See* PJM MMU Settlement Order, 122 FERC ¶ 61,257.

[411] In the event of any inconsistencies, the requirements imposed in this Final Rule, which have the force of regulation, would control. Indeed, the PJM/MMU Settlement Agreement itself so acknowledges, as the Commission noted in its order approving the settlement. *Id.* P 24.

[412] NOPR at P 182.

[413] American Forest, APPA, CAISO, DC Energy, EPSA, FTC, Industrial Consumers, ISO New England, LPPC, Midwest ISO, New York PSC, North Carolina Electric Membership, NRECA, NYISO, Old Dominion, PJM Power Providers, Reliant, SPP and TAPS.

[414] APPA at 81.

[415] FTC at 30.

[416] CAISO; California PUC; EEI; NYISO; and Reliant.

or their designees. Ohio PUC believes this construct would provide MMU autonomy and relieve the board of directors of the RTO or ISO from arbitrating disputes between an RTO or ISO and the MMU.[417]

338. Four commenters disagree with the Commission's proposal not to impose a blanket requirement that major changes in the MMU's employment arrangements be subject to Commission review and approval.[418] APPA states that substantial changes such as contract termination and renewal for external market monitors, or major changes in employment arrangements for internal market monitors, should be subject to Commission review and approval. It also suggests that the Commission adopt the pertinent provision of the PJM/MMU Settlement Agreement as a ''best practice,'' reasoning that this would give MMUs a measure of job security that might allow them to be more independent in their assessments.[419] California PUC and Steel Producers agree that significant relational changes should be subject to Commission review, including changes to the structure of an MMU or the dismissal of key MMU personnel.[420] TAPS states that Commission review of important changes would provide a backstop to ensure MMU independence, and would give market participants and the Commission a mechanism to assess whether an RTO or ISO has fulfilled its obligations toward the MMU. It argues that the Commission has not provided a valid reason not to require approval of such MMU changes.[421]

iii. Commission Determination

339. We adopt the NOPR proposal requiring MMUs to report to the RTO or ISO board of directors, with management representatives on the board excluded from this oversight function. Removing the MMU from reporting to management will give it the separation needed to foster independence. If occasion demands, we will revisit this decision. However, we decline to ''earmark'' it for periodic review as requested by the FTC. We also adopt the NOPR proposal allowing RTOs and ISOs, if they deem it appropriate, to permit the MMU to report to management for administrative purposes, such as pension management, payroll and the like.

340. Commenters generally agreed with our proposed exception for hybrid MMUs, in which we suggested that the internal market monitor may continue to report to management, while the external market monitor should report to the board. But TAPS points out that in some hybrid structures, the most important functions of the MMU are performed by the internal market monitor, with the external market monitor playing a much ''weaker'' role. We agree that such a division of labor presents a problem, and could result in the rule being swallowed by the exception.

341. However, we decline to adopt TAPS's suggested solution of requiring the external market monitor to assume responsibility for the core MMU duties spelled out in this order (identifying ineffective market rules, reviewing the performance of the markets, and making referrals to the Commission). This solution might impose upon the RTO or ISO an MMU structure that it does not want. Instead, we will require that if the internal market monitor is responsible for carrying out any or all of the above-cited core MMU functions, it must report to the board (as must the external market monitor). This solution allows the RTO or ISO to structure its MMU function in the way it deems most suitable, while also ensuring that the market monitor that performs the core MMU functions enjoys the independence from management that reporting to the board accomplishes.

342. Ohio PUC suggests that reporting to the RTO or ISO board should be an interim step only, and that ultimately MMUs should report to a Federal-State Joint Board on Market Monitor Oversight. Not only does an arrangement of this type raise jurisdictional concerns, it is difficult to see how such a potentially cumbersome structure could oversee MMUs in a timely and responsive manner. It is also doubtful that such an arrangement could effectively replicate the existing close exchange of data between the RTO or ISO and its MMU. Should the reforms we adopt in this Final Rule fail to achieve the needed independence we envision for MMUs, we will not hesitate to rectify the situation.

343. Several commenters propose that changes in the RTO/ISO/MMU relationship, such as contract termination or the dismissal of key MMU personnel, should be made subject to Commission review.[422] We noted in the NOPR that as of the date of its issuance, three of the RTOs and ISOs had agreements in place that provided for such review.[423] Since that date a fourth has been added, that of PJM.[424]

344. These RTOs and ISOs have voluntarily consented to such review. In the absence of such consent, we decline to impose a blanket requirement that RTOs and ISOs make their MMUs' contractual and employment arrangements subject to Commission review. Should the situation arise in which an RTO or ISO terminates its MMU in such a way as to violate its tariff requirements concerning MMU independence, the Commission will address such a violation on case-by-case basis.

c. Functions

i. Commission Proposal

345. In the NOPR, the Commission proposed updating and expanding the core tasks that our May 2005 Policy Statement on Market Monitoring Units required MMUs to perform. We proposed that the MMU be responsible for evaluating market rules, tariff provisions and market design elements for their effectiveness, and proposing recommended changes; reviewing and reporting on the performance of the wholesale markets; and referring suspected wrongdoing to the Commission.

346. In furtherance of its goal of ensuring independent analysis on the part of MMUs, the Commission also proposed that RTOs and ISOs include a provision in their tariffs specifying that they may not alter the reports generated by the MMUs or dictate the conclusions reached by the MMUs, although they may establish a reasonable mechanism for review and comment on MMU reports that are still in draft form. The

[417] Ohio PUC at 16–21.

[418] APPA; California PUC; Steel Producers; and TAPS.

[419] APPA at 82.

[420] California PUC at 34; Steel Producers at 11–12.

[421] TAPS at 49.

[422] To the extent commenters request that structural changes be made subject to Commission review, we note that such matters are governed by tariff and any change to the MMU structure (such as whether an MMU is internal, external or a hybrid) would require a tariff filing.

[423] Midwest ISO cannot terminate its agreement with its market monitor (an independent contractor) without Commission approval. Open Access Transmission and Energy Markets Tariff for the Midwest Independent Transmission System Operator, Inc., Attachment S–1, FERC Electric Tariff, Third Revised Volume No. 1, Second Revised Sheet No. 1659 (2005). SPP cannot terminate its agreement with its external market monitor without Commission approval. Southwest Power Pool Open Access Transmission Tariff, FERC Electric Tariff Fourth Revised Volume 1, Attachment AJ, § 11, Second Revised Sheet No. 699 (2006). The same is true for ISO New England. Participants Agreement among ISO New England, Inc. and the New England Power Pool, *et al.*, § 9.4.5.

[424] Settlement Agreement and Explanatory Statement of the Settling Parties, Docket Nos. EL07–56–000 and EL07–58–000 (December 19, 2007), Attachment M, PJM Market Monitoring Plan, III.F.3.e. This agreement was approved by the Commission in the PJM MMU Settlement Order.

Commission noted that this proposal will enable the MMU to receive potentially helpful comments, while removing the ability of the RTO or ISO to unreasonably influence or impede the MMU's analysis.

ii. Comments

347. All but two commenters support the Commission's proposal regarding the three core functions of an MMU.[425] ISO New England would add a fourth function, that of regular daily monitoring of the wholesale market in order to obtain timely access to information that would provide a broader context for evaluating particular types of conduct, and that could speed and enhance detection of manipulative behavior.[426] TAPS would also add a fourth function, that of assessing whether RTO benefits flow to consumers. It suggests that the MMU could make this consumer-value assessment by examining, for example, whether in LMP markets investment in transmission, generation and demand response is occurring in areas with higher prices, and whether FTRs are available, and are being used, to hedge transmission congestion costs experienced by LSEs.[427]

348. CAISO requests clarification that when an MMU evaluates existing and proposed market rules, the Commission expects it to employ its best judgment about effective use of resources, and does not expect a formal evaluation for every existing market rule.[428] California PUC agrees that an MMU should identify ineffective market rules and tariff provisions and recommend proposed rule and tariff changes; however, it suggests the MMU's participation be limited to an advisory role.[429] NY TOs and PJM state that MMUs should evaluate changes, but should not get involved in implementing changes.[430] PG&E believes the Final Rule should authorize MMUs to access data necessary to assess the impact of behavior outside of an RTO's or ISO's geographic footprint, commenting that such access is needed in California because the state is very dependent on imports. It also states that MMUs should report on the effectiveness and comprehensiveness of mitigation as part of their duties, even when they are not themselves directly involved in implementation of such mitigation.[431]

349. Two commenters agree with the Commission's proposal that MMUs should limit dissemination of information in those cases where disclosure of a market design loophole could be exploited.[432] APPA believes MMUs should disclose such information at an appropriate time, such as when tariff changes or software upgrades are adopted, in order to maintain transparency.[433] Reliant requests clarification as to whether MMUs should provide the RTO or ISO, stakeholders and the Commission with their views as to whether existing operations interfere with appropriate market signals.[434]

350. All three commenters addressing the subject agree that MMUs should report violations of Standards of Conduct (18 CFR Part 158) or Affiliate Restrictions rules (18 CFR 35.39) rules if uncovered in the ordinary course of business.[435] California PUC states that violations should be referred to the appropriate state commission as well as to the Commission.[436]

351. Commenters agree that RTOs should not be allowed to alter reports generated by an MMU.[437] APPA does not support a tariff provision allowing MMUs to submit their reports in draft form to RTOs for review and comment. It states that the Commission approved a specific prohibition against such review in the PJM/MMU Settlement Agreement, and should adopt such a prohibition in this proceeding.[438]

352. Old Dominion suggests that if the MMU disagrees with a tariff change that the RTO or ISO proposes to the Commission, the RTO or ISO should file both its proposal and that of the MMU.[439]

iii. Commission Determination

353. We adopt the MMU functions proposed in the NOPR, with clarifying rewording. These functions expand and update the functions already performed by MMUs in accordance with the Policy Statement and codify the protocols for referrals to the Commission discussed therein.[440] The revised functions should provide MMUs with ample authority to evaluate any needed changes to the markets and bring them to the attention of concerned entities, to review and report on the performance of the markets, and to refer suspected wrongdoing to the Commission.

354. As we have previously acknowledged:

> MMUs perform an important role in assisting the Commission in enhancing the competitiveness of ISO/RTO markets. Competitive markets benefit customers by assuring that prices properly reflect supply and demand conditions. MMUs monitor organized wholesale markets to identify ineffective market rules and tariff provisions, identify potential anticompetitive behavior by market participants, and provide the comprehensive market analysis critical for informed policy decision making.[441]

Thus, the MMU functions we adopt are as follows:

> (1) Evaluating existing and proposed market rules, tariff provisions and market design elements, and recommending proposed rule and tariff changes not only to the RTO or ISO, but also to the Commission's Office of Energy Market Regulation staff and to other interested entities such as state commissions and market participants, with the caveat that the MMU is not to effectuate its proposed market design itself (a task belonging to the RTO or ISO), and with the further caveat that the MMU should limit distribution of its identifications and recommendations to the RTO or ISO and to Commission staff in the event it believes broader dissemination could lead to exploitation, with an explanation of why further dissemination should be avoided at that time;
>
> (2) Reviewing and reporting on the performance of the wholesale markets to the RTO or ISO, the Commission, and other interested entities such as state commissions and market participants; and
>
> (3) identifying and notifying the Commission's Office of Enforcement staff of instances in which a market participant's behavior, or that of the RTO or ISO, may require investigation, including suspected tariff violations, suspected violations of Commission-approved rules and regulations, suspected market manipulation, and inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.

355. We decline to add as a fourth function ISO New England's proposal regarding daily monitoring of the wholesale market, as this function is included in the existing requirement to review and report on the performance of the wholesale markets.

356. CAISO requests clarification that the Commission does not expect an MMU to make a formal evaluation of every existing market rule. We agree. The MMU's role is one of monitoring, not auditing, and we do not expect it to

[425] CAISO; California PUC; DC Energy; EEI; Industrial Consumers; ISO New England; Midwest ISO; North Carolina Electric Membership; NY TOs; PG&E; PJM; Reliant; SPP; and TAPS.

[426] ISO New England at 18.

[427] TAPS at 51–52.

[428] CAISO at 14.

[429] California PUC at 34–35.

[430] NY TOs at 3; PJM at 6.

[431] PG&E at 15–16.

[432] APPA; Reliant.

[433] APPA at 83.

[434] Reliant at 12–13.

[435] California PUC; EPSA; and Midwest ISO.

[436] California PUC at 36–37.

[437] APPA; NRECA; NSTAR; Old Dominion; PJM; and SPP.

[438] APPA at 83–84.

[439] Old Dominion at 21–22.

[440] Policy Statement, 111 FERC ¶ 61,267 at Appendix A.

[441] *Id.* P 1.

make a systematic and comprehensive review of every one of the thousands of existing market rules. For this reason, we decline to adopt TAPS's suggested fourth function of assessing whether RTO or ISO benefits flow to consumers. Finally, we expect MMUs to be vigilant in identifying problems and bringing them to the attention of the RTO or ISO, the Commission, and other interested entities.

357. We agree that the MMU's role in recommending proposed rule and tariff changes is advisory in nature, and that the MMU should not become involved in implementing rule and tariff changes (unless a tariff provision specifically concerns actions to be undertaken by the MMU itself). Both the filing of proposed rule and tariff changes, and the implementation of rule and tariff changes, are within the purview of the RTO or ISO. However, we do expect the MMU to advise the Commission, the RTO or ISO, and other interested entities of its views regarding any needed rule and tariff changes. Likewise, in the event an RTO or ISO files for a proposed tariff change with which the MMU disagrees, we expect the RTO or ISO to inform the Commission of that disagreement, although not necessarily to include a written MMU proposal with its filing.

358. We also concur with PG&E that where data concerning activity outside the geographical footprint of the RTO or ISO would be helpful to the MMU in carrying out its functions, the MMU should seek out such data. Likewise, where an MMU believes market design flaws interfere with appropriate price signals, these flaws should be brought to the attention of concerned entities. And, where information about a market design flaw was not broadly disseminated because the MMU felt such information could alert market participants to a market loophole, such information can, and should, be provided once the danger of exploitation of the loophole is past.

359. The California PUC requests that violations of the Standards of Conduct or Affiliate Restrictions should be reported to the appropriate state commission as well as to the Commission. We decline to adopt this proposal. These are violations of Commission rules, not of state rules or statutes, and therefore the Commission is the proper body to investigate them.

360. We adopt the NOPR proposal that, by tariff, each RTO or ISO may require its MMU to submit its report in draft form to the RTO or ISO for review and comment, but may not alter the reports generated by the MMU or dictate the MMU's conclusions. RTOs or ISOs need not require submission of draft reports, but if they do, input from knowledgeable employees may serve to strengthen the end product or catch errors of fact or reasoning. In any event, the MMU is free to disregard any suggestions with which it disagrees.

d. Mitigation and Operations

i. Commission Proposal

361. In order to strengthen MMU independence, the Commission proposed in the NOPR that MMUs be removed from tariff administration, including mitigation. This proposal was designed to free MMUs from a role that might make them subordinate to the RTO or ISO. The Commission regulates public utilities, and it is the public utilities that we hold accountable for tariff implementation. To the extent this function is performed by MMUs, the MMUs are assisting the RTOs and ISOs in the administration of their tariff, which places the MMUs in a subordinate position to the RTOs and ISOs. The proposal was also designed to remove the bias that might arise from the MMUs' analyzing the health of the markets they themselves had affected. The Commission solicited comments on the activities that would be needed to make the transition to RTO or ISO-administered mitigation, on any difficulties the MMU might be anticipated to experience in monitoring mitigation performed by the RTO or ISO, and any additional sensitivities that commenters wished to raise regarding the proposal.

ii. Comments

362. Several commenters support the Commission's proposal to remove MMUs from RTO and ISO tariff administration, including mitigation.[442] However, many more oppose it.[443]

363. The commenters who agree with the Commission's proposal advance several arguments in support of it. Two entities cite two conflicts of interest that may arise when an MMU is involved in mitigation and tariff administration, the first occurring when an MMU both evaluates market performance and conducts mitigation,[444] and the second occurring when an MMU assists in designing and finalizing a rule for filing with the Commission and subsequently evaluates the effectiveness of the rule in practice.[445] Another commenter states that an MMU should be limited to the three core functions the Commission enunciated in the NOPR, leaving it free to advise the Commission of perceived instances where the RTO or ISO itself has failed to conduct economic dispatch in an efficient manner.[446] Other commenters state that the rules and actions related to mitigation should be made explicit and, to the extent possible, be automated and implemented via bright-line tests, in order to eliminate discretion in their application.[447]

364. The commenters who oppose the Commission's proposal advance several arguments why RTOs and ISOs should not perform mitigation. Commenters suggest that the RTO or ISO staff and personnel who have designed and implemented the markets, and whose compensation is based upon those tasks, may have a vested interest in not identifying or correcting problematic behavior, and may have an interest in not imposing enforcement measures on what in effect are their customers, or in refraining from mitigating a member that threatens to leave the RTO or ISO.[448] Other commenters remark that removing the MMU from mitigation activities may deprive the MMU of much of the hands-on administrative interaction with participants that is essential to consumer protection.[449] One commenter suggests that a better way to address the issue is to issue additional orders limiting discretion in applying mitigation, rather than removing MMUs from mitigation activities.[450] Other commenters argue that moving mitigation responsibility from an MMU to the RTO or ISO would deprive the MMU of timely, first-hand access to crucial information that could speed and enhance detection of manipulative behavior, noting that after-the fact mitigation (settlement price adjustment) would not be a function of the market that the MMU would be able to view once it was removed from tariff administration.[451] ISO New England states that mechanistic application of mitigation criteria by RTOs or ISOs would not readily address shifts in bidding behaviors, and that as market participants continuously search for

[442] Ameren; EPSA; FirstEnergy; Industrial Consumers; PG&E; PJM; Reliant; SoCalEdison-SDG&E; and SPP.

[443] American Forest; California PUC; Indianapolis P&L; Industrial Coalitions; Maine PUC; NARUC; NEPOOL Participants; New York PSC; North Carolina Electric Membership; Ohio PUC; Old Dominion; OMS; Potomac Economics; and Xcel.

[444] Ameren at 33; PJM at 4–6.

[445] Ameren at 33; PJM at 5–6.

[446] FirstEnergy at 14–15.

[447] Reliant at 13; Potomac Economics at 8–9.

[448] American Forest at 6; California PUC at 37–38; Indianapolis P&L at 4; Industrial Coalitions at 21–22; Midwest ISO at 24–26; Ohio PUC at 24–25; and OMS at 16–17.

[449] American Forest at 7; ISO New England at 19–22; and NARUC at 12–13.

[450] American Forest at 7.

[451] ISO New England at 20–21; Xcel at 12–13.

more profitable bidding strategies, the discretion of a skilled MMU to investigate unusual bidding behavior inhibits experimentation with deviant strategies and enhances deterrence.[452] ISO New England states that the Commission's conflict of interest concern is inconsistent with grounding MMU independence and objectivity in its code of conduct and contractual obligations, and notes that the MMU has nothing to gain financially from mitigation.[453] ISO New England and Maine PUC state that moving the mitigation activity to the RTO or ISO could require additional operational staff to perform tasks that MMU employees can accomplish on an integrated basis and more efficiently, thereby increasing RTO or ISO costs.[454] NYISO estimates that an additional five to eight employees would be required because of the need to duplicate some functions in order for the MMU to monitor the RTO or ISO's conduct of mitigation.[455]

365. Indianapolis P&L states that moving the mitigation function to the RTO or ISO raises the potentially serious problem of retaliation, because if RTO or ISO stakeholders disagree with the direction in which the RTO or ISO wishes to move, the RTO or ISO could be tempted to use the market mitigation power as a tool of persuasion.[456] OMS states that in the absence of a specific showing that an MMU is incapable of applying mitigation measures appropriately, the Commission should respect the decision of the RTO or ISO and stakeholders in this regard. It also observes that RTOs and ISOs have greater incentive than MMUs not to mitigate, as an entity might be inclined to withdraw from membership in response. It does not regard a referral to the Commission of an RTO's or ISO's failure to properly mitigate as a sufficient remedy, as such referrals are kept confidential.[457]

366. SoCal Edison-SDG&E support the Commission's proposal only if the following conditions occur: (1) Adequate assurance of effective mitigation is provided; (2) MMUs have full access to data used for mitigation; and (3) MMUs are allowed to participate in all activities used to develop mitigation rules and specific mitigated bid levels for individual generators.[458] PG&E supports it only if: (1) RTO and ISO tariffs are modified to include sufficient staff resources to perform mitigation; (2) mitigation staff are free from the influence of other RTO staff; and (3) mitigation staff has the right to report to the Commission and its Office of Enforcement any loopholes or deficiencies in mitigation design or implementation.[459]

367. EEI, ISO New England, Maine PUC and New York PSC oppose the proposal for cases where the RTO or ISO has a hybrid MMU structure.[460] Midwest ISO opposes the proposal when it is applied mechanically to all RTOs and ISOs.[461] NRECA states that any changes in the Final Rule should not weaken mitigation, should not supersede the PJM/MMU Settlement Agreement, and should follow the Final Rule in Order No. 697.[462] CAISO notes that its internal monitor does not administer mitigation, but does administer an Enforcement Protocol related to late fees and the untimely submission of outage reports and meter data,[463] and seeks guidance as to whether these activities would constitute "tariff administration" under the Final Rule.[464] TAPS does not oppose the proposal, but thinks MMUs can function better doing mitigation.[465]

368. Potomac Economics and APPA offer compromise positions and clarifications. APPA suggests that the MMU continue to review bids, but refrain from participating directly in drafting proposed changes to the mitigation rules; rather, the MMU would comment on the proposed rules and, if necessary, become a separate intervenor in a Commission proceeding if one were to occur.[466]

369. Potomac Economics observes that the aspects of mitigation that the Commission appears to find objectionable are those that are applied prospectively to participant offers and thus affect market outcomes (such as altering the prices of offers or altering the physical parameters of offers such as ramp rates and start-up time). Potomac Economics proposes that the Commission clarify that the RTO or ISO should be responsible for implementing these prospective mitigation measures, while the MMU be allowed to be responsible for implementing retrospective measures such as calculation of after-the-fact mitigation true-ups for billing purposes and settlement price adjustments. Potomac Economics also suggests that MMUs continue to be responsible for the production of inputs into the mitigation process, such as reference levels and the identification of system constraints, which rely on the MMUs' intimate knowledge of the market and their software capabilities. Potomac Economics believes that this bifurcation of labor would avoid the wasteful duplication of software, staff and expertise that would be needed for the RTO or ISO to mirror all of the MMU's mitigation capabilities, that it contends the MMU would have to retain in order to satisfy its market monitoring obligations.[467]

iii. Commission Determination

370. The proposal in the NOPR to remove MMUs from tariff administration, and in particular from mitigation, engendered heated disagreement amongst the commenters. Several supported the proposal, although the majority disagreed with removing the MMU from mitigation. The Commission has given careful consideration to the comments, and acknowledges that there are valid concerns on both sides.

371. As we observed in the NOPR, and as many commenters noted as well, there is an inherent conflict of interest in an MMU conducting mitigation and also opining on the state of the market, the health of which may in part reflect the results of its mitigation. We also observed that by supporting RTOs and ISOs in tariff administration, MMUs become subordinate to the RTO or ISO, thus weakening their independence.

372. Many commenters, however, raise substantial concerns over removing MMUs from mitigation, including the following: (1) There is a greater conflict of interest for the RTO or ISO to administer mitigation, as it has a vested interest in keeping its market participants happy, especially the larger players who can threaten to leave the

[452] ISO New England at 21.

[453] *Id.* at 21–22 (citing *ISO New England Inc.,* 119 FERC ¶ 61,045, at P 123 (2007), *reh'g granted in part and denied in part,* 120 FERC ¶ 61,087 (2007)); NEPOOL Participants at 23 (citing *ISO New England Inc.* 106 FERC ¶ 61,280, P 187 (2004), reh'g *granted in part and denied in part,* 109 FERC ¶ 61,147 (2004); *Order Authorizing RTO Operations;* 110 FERC ¶ 61,111 (2005); *order on reh'g,* 111 FERC ¶ 61,344 (2005); *ISO New England Inc.,* 120 FERC ¶ 61,087, at P 52 (2007)).

[454] ISO New England at 22; Maine PUC at 7.

[455] NYISO at 16.

[456] Indianapolis P&L at 4.

[457] OMS at 8–9.

[458] SoCal Edison-SDG&E at 4.

[459] PG&E at 17.

[460] EEI at 24–25, ISO New England at 19–22; Maine PUC at 7; and New York PSC at 6–8.

[461] Midwest ISO at 24–26.

[462] *Market-Based Rates For Wholesale Sales Of Electric Energy, Capacity, And Ancillary Services By Public Utilities,* Order No. 697, FERC Stats. & Regs. ¶ 31,252, at P 241 (2007), *order on reh'g,* Order No. 697–A, 73 FR 25,832 (May 7, 2008), FERC Stats. & Regs. ¶ 31,268 (2008).

[463] *Calif. Indep. Sys. Operator Corp.,* 106 FERC ¶ 61,179, at P 154; *order on reh'g,* 107 FERC ¶ 61,118; *reh'g denied,* 109 FERC ¶ 61,089 (2004); *order on reh'g,* 110 FERC ¶ 61,333 (2005).

[464] CAISO at 15–16.

[465] TAPS at 52–53.

[466] APPA at 84–85.

[467] Potomac Economics at 8–10.

RTO or ISO if they choose; (2) the MMU serves as a useful buffer between the RTO or ISO and the market participants, performing what is often viewed as a hostile act; (3) there is an inherent tension between mitigation and the RTO or ISO goal of promoting new markets; (4) the MMU is better equipped by training and market access to detect the need for mitigation; (5) removing the MMU from mitigation would distance it from the market insights it needs to perform its monitoring functions; (6) if removed from tariff administration, the MMU would not have access to the mitigation settlement process and thus could not adequately monitor the RTO's or ISO's mitigation performance; (7) there would be much duplication of costs, since the MMU would have to retain most of its mitigation capabilities in order to monitor the RTO's or ISO's conduct of mitigation; (8) there would be extensive transition costs and software licensing concerns; and (9) there is no empirical evidence of an existing problem with the MMUs performing mitigation.

373. We find many of the objections raised by commenters meritorious. However, we remain concerned that the unfettered conduct of mitigation by MMUs makes them subordinate to the RTOs and ISOs and raises conflict of interest concerns. Therefore, we adopt a compromise approach, one that strikes the appropriate balance between allowing modified participation by the MMUs in mitigation, while protecting against the conflict of interest and subordination inherent in their unfettered participation.

374. As the first element of this approach, we direct that in the event an RTO or ISO employs a hybrid MMU structure, it may authorize its internal MMU to conduct mitigation. An internal MMU is a part of the RTO or ISO, and allowing it to conduct mitigation adequately separates it from the monitoring duties of the external market monitor and places mitigation within the RTO or ISO itself. However, this solution only works if the external market monitor is charged with the responsibility of reviewing the quality and appropriateness of the mitigation conducted by the internal market monitor. We therefore require that in the event an RTO or ISO with a hybrid MMU structure permits its internal market monitor to conduct mitigation, it must assign its external market monitor the responsibility, and give it adequate tools, to monitor the quality and appropriateness of that mitigation.

375. As the second element of our approach, we find useful Potomac Economics' distinction between prospective and retrospective mitigation. It is only prospective mitigation that affects the operation of the market, and therefore it is only prospective mitigation that creates a potential conflict of interest for an MMU. Therefore, we direct that RTOs and ISOs may allow their MMUs, regardless of whether it uses a hybrid structure, to conduct retrospective mitigation. For these purposes, we consider prospective mitigation to include only mitigation that can affect market outcomes on a forward-going basis, such as altering the prices of offers or altering the physical parameters of offers (*e.g.*, ramp rates and start-up times) at or before the time they are considered in a market solution. All other mitigation would be considered retrospective. We also determine that the MMU may provide the inputs required by the RTO or ISO to conduct prospective mitigation, including determining reference levels, identifying system constraints, cost calculations and the like. This will enable the RTO or ISO to utilize the considerable expertise and software capabilities developed by their MMUs, and reduce wasteful duplication.

376. As noted by Potomac Economics and by PJM in its supplemental comments, a number of our orders specifically lodge elements of mitigation and administration within the MMUs. Many of these may properly be considered retroactive mitigation, and the RTOs' or ISOs' tariffs would not need to be adjusted to remove these responsibilities from the MMU's purview. Should there be any question of categorization, whether for existing or proposed tariff provisions, the RTO or ISO may seek guidance from the Commission in its compliance filing.

377. We also direct that purely administrative matters, such as those identified by CAISO (enforcement of late fees and the untimely submission of outage reports and meter data), should be conducted by the RTO or ISO, rather than the MMU. Such activities are remote from the core duties that this Final Rule assigns to the market monitoring function.

378. We also direct that the tariffs of RTOs and ISOs clearly state which functions are to be performed by MMUs, and which by the RTO or ISO. This separation of functions will serve to eliminate RTO or ISO influence over the MMUs, and remove the concern that MMU assistance in mitigation makes it subordinate to the RTO or ISO.

379. Finally, we direct the RTOs and ISOs to review their mitigation tariff provisions with a view to making them as non-discretionary as possible, whether performed by the MMU or by the RTO or ISO, and to reflect any needed changes in their compliance filings. This will go a long way toward removing the ability of either entity to act in a discriminatory manner, and will facilitate the monitoring and review of mitigation activities.

e. Ethics

i. Commission Proposal

380. In the NOPR, the Commission proposed that development of particular ethics standards to be applied to MMUs should be left in the first instance to the discretion of the RTOs and ISOs. However, the Commission noted that these standards should include certain minimum requirements, as follows: (1) Employees shall have no material affiliation (to be defined by the RTO or ISO) with any market participant or affiliate; (2) employees shall not serve as an officer, employee, or partner of a market participant; (3) employees shall have no material financial interest in any market participant or affiliate (allowing for such potential exceptions as mutual funds and non-directed investments); (4) employees shall not engage in any market transactions other than the performance of their duties under the tariff; (5) employees shall not be compensated, other than by the RTO or ISO, for any expert witness testimony or other commercial services to the RTO or ISO or to any other party in connection with any legal or regulatory proceeding or commercial transaction relating to the RTO or ISO or to the RTO or ISO markets; (6) employees may not accept anything of value from a market participant in excess of a *de minimis* amount, to be decided on by the RTO or ISO; and (7) employees must advise their supervisor (or, in the case of the MMU manager, advise the RTO or ISO board) in the event they seek employment with a market participant and must disqualify themselves from participating in any matter that would have an effect on the financial interest of such market participant.[468]

ii. Comments

381. All commenters addressing the subject agree that ethical standards should be imposed on MMU

[468] The Commission noted that some external MMUs may currently have business associations that would be prohibited under these proposed minimum requirements, such as unrelated consulting work for participants in its RTO's or ISO's markets. If that is the case, the Commission proposed that the RTO or ISO should propose a suitable transition plan in its compliance filing. NOPR, FERC Stats. & Regs. ¶ 32 ,628 at n.200.

employees.[469] All but one of these commenters agree that the standards should appear in a tariff provision, thus making the MMU subject to an enforcement action. However, FirstEnergy, stating that it is opposed to collecting from RTO or ISO members any penalties assessed to an RTO or ISO, prefers that the MMU adopt ethics standards internally and implement them by managing and disciplining its employees.[470] APPA and Ohio PUC suggest adding a provision to the standards covering post-employment activities.[471] Midwest ISO states its market monitor performs independent work for other entities under Commission-approved monitoring plans, and requests clarification that the minimum guidelines the Commission proposes would not prohibit other employees of the MMU's firm from performing independent monitoring for other entities. Potomac Economics, the Midwest ISO's MMU, requests the same clarification, noting that the work is not done on behalf of the company.[472] NRECA asserts that ethics standards should include civil penalties.[473]

382. Potomac Economics proposes that the Commission should include the phrase ''other than the RTO or ISO'' after the first clause in proposed minimum requirement (5), as omission of the phrase would prohibit compensation of MMU employees for any expert witness testimony or other commercial services on behalf of the Commission-approved RTO or ISO, thus preventing the MMU from performing many of the required market monitoring functions.[474]

iii. Commission Determination

383. There was widespread agreement among the commenters that ethics standards should be imposed, and the importance of such standards calls for their inclusion in the RTO's or ISO's tariff, subject to enforcement by the Commission. (The manner of such potential enforcement, including whether civil penalties might be imposed and the avenue by which any such penalties might be collected, is beyond the scope of this Final Rule.[475]) Therefore, we direct that each RTO and ISO include in its tariff the minimum ethics standards set forth in the NOPR, with certain modifications as set forth below.

384. We note that the requirements we impose are minimums, and an RTO or ISO is free to propose more stringent ones. Therefore, the appropriate place to request additional requirements, such as the suggested extension of the standards to post-employment activities, would be in stakeholder meetings, or before the Commission when the RTO or ISO makes its tariff compliance filing.

385. Midwest ISO and Potomac Economics request clarification that the ethics standards do not prohibit employees of the MMU from performing monitoring for entities other than RTOs or ISOs. We clarify that if the employing entity is not a market participant in the particular RTO or ISO for whom the MMU already performs market monitoring, such engagement is permissible. However, if the employing entity is a market participant in the RTO or ISO for whom the MMU already performs market monitoring, the proposed work would entail the same conflict of interest as would any other consulting services. We are cognizant of the fact that if an MMU currently has such engagements in place, it will take a certain amount of time to unwind the association or make other suitable arrangements. We direct the RTO or ISO to apprise the Commission of such engagements in its compliance filing, and to propose a transition plan for dealing with them in a manner consistent with the aims expressed in this Final Rule, as the Commission proposed in the NOPR.[476]

386. We agree with Potomac Economics that the NOPR's regulatory text inappropriately omitted the phrase ''other than the RTO or ISO'' after the first clause of proposed minimum ethical requirement (E). (The phrase was included in the body of the NOPR itself). We direct that the RTO and ISO tariffs should include the omitted phrase, and we correct the regulatory text in this Final Rule.

387. We also note that both the body of the NOPR and the regulatory text refer to ''employees,'' whereas the intent of the provision encompasses both the MMU itself as well as its employees. We therefore direct the RTOs and ISOs to specify that their MMU ethics standards apply to the MMU itself as well as to its employees.

f. Tariff Provisions

i. Commission Proposal

388. The Commission proposed in the NOPR that RTOs and ISOs be required to include in their tariffs, and centralize in one section, all of their MMU provisions. We noted that including all MMU provisions in the tariff will ensure they are made subject to the compliance requirements that attach to tariff provisions, and thus will give to interested parties notice and an opportunity to intervene when a tariff filing is made.

389. The Commission also proposed that RTOs and ISOs include an MMU mission statement in the introductory portion of its MMU tariff section, setting forth the goals to be achieved by the MMU, including the protection of both consumers and market participants by the identification and reporting of market design flaws and market power abuses.

390. The Commission further proposed that the RTOs and ISOs meet these requirements at the time they make their compliance filings in connection with this proceeding.

ii. Comments

391. Commenters support the proposal to locate all MMU provisions in one section of the RTO or ISO tariffs.[477] Two commenters agree these provisions should include a mission statement.[478] APPA states the best starting point for this kind of statement is Attachment M to the PJM/MMU Settlement Agreement.[479] FirstEnergy opposes the option of leaving existing MMU provisions in their current location in addition to placing them in a new section of the tariff, since it believes this would be administratively inconvenient and has the potential to create inconsistencies.[480] PG&E does not oppose posting MMU provisions elsewhere than in the MMU section, so long as appropriate cross-referencing is made.[481]

iii. Commission Determination

392. We adopt the NOPR proposal and direct RTOs and ISOs to include in their tariffs, and centralize in one section, all of their MMU provisions. We also direct RTOs and ISOs to include a mission statement in the

[469] Ameren; APPA; CAISO; California PUC; DC Energy; EEI; FirstEnergy; Industrial Consumers; ISO New England; Midwest ISO; North Carolina Electric Membership; NRECA; Ohio PUC; PG&E; PJM Power Providers; Potomac Economics; Reliant; SPP; and TAPS.

[470] FirstEnergy at 15–16.

[471] APPA at 86; Ohio PUC at 25–26.

[472] Midwest ISO at 26–27; Potomac Economics at 13.

[473] NRECA at 53–54.

[474] Potomac Economics at 11–13.

[475] *See Revised Policy Statement on Enforcement*, 123 FERC ¶ 61,156 (2008) (discussing the factors to be considered in determining what, if any, remedies are to be imposed in the case of violations of Commission rules and regulations).

[476] NOPR, FERC Stats. & Regs. ¶ 32,628 at P 200.

[477] Ameren; APPA; California PUC; Constellation; DC Energy; EEI; FirstEnergy; Industrial Consumers; ISO New England; Midwest ISO; North Carolina Electric Membership; Old Dominion; PG&E; Reliant; SPP; and Xcel.

[478] APPA at 87; EEI at 25.

[479] APPA at 87.

[480] FirstEnergy at 14.

[481] PG&E at 18–19.

introductory portion of their MMU tariff section, which is to set forth the goals to be achieved by the MMU, including the protection of both consumers and market participants by the identification and reporting of market design flaws and market power abuses.

393. We adopt the suggestion that RTOs and ISOs may include various MMU provisions elsewhere in their tariff as well as in the centralized MMU section, if they believe context and clarity so require. However, we are sympathetic to the concern that this duplicative listing may create confusion. Therefore, we require RTOs and ISOs, if they make such a duplicative listing, to clearly note that the provision in question is also found in the centralized MMU section. We also direct the RTO or ISO to include in its tariff a provision stating that in the event of any inconsistency between provisions in the centralized MMU section and provisions set forth elsewhere, the provisions in the centralized MMU section control. Of course, the RTO or ISO should attempt to avoid any such inconsistencies.

394. We direct RTOs and ISOs to include their centralized MMU tariff sections in their compliance filings to be made in connection with this Final Rule.

3. Information Sharing

a. Enhanced Information Dissemination

i. Commission Proposal

395. The Commission carried forward proposals in the NOPR that had been advanced in the ANOPR, and which were designed to enhance the dissemination of information by MMUs in several areas. Specifically, the Commission proposed that MMUs report on aggregate market performance on no less than a quarterly basis to Commission staff, to staff of interested state commissions, and to the management and board of directors of the RTOs or ISOs. The Commission also proposed the MMUs make one or more of their staff members available for regular conference calls with representatives from the Commission, state commissions and the RTO or ISO. In the NOPR, the Commission stated that the type of information to be released by the MMU may most fruitfully continue to be developed on a case-by-case basis, so long as it generally consists of market analyses of the type regularly gathered by the MMUs in the course of business, and so long as it remains subject to appropriate confidentiality restrictions.

396. The Commission proposed that market participants be included in the dissemination of reports, which could be accomplished via posting them on the RTO or ISO Web site. However, the Commission stated that including market participants on conference calls would be unwieldy, and proposed limiting participation on such calls to Commission staff, RTO and ISO staff, staff of interested state commissions, and staff of state attorneys general should they express a desire to attend.

397. While the Commission noted that quarterly reports should not be as extensive as the annual state of the market report, it also stated that the annual state of the market reports have proven to be useful documents, and proposed that the RTOs and ISOs include in their tariffs a requirement for the MMUs to produce them, with the same dissemination (or broader, if desired) as the quarterly reports.

398. The Commission also proposed that the time period for the release of offer and bid data be reduced to three months, but that an RTO or ISO could propose a shorter period with accompanying justification or, if it demonstrates a potential collusion concern, a four-month lag period or some other mechanism to delay the release of a report if the release were otherwise to occur in the same season as reflected in the data.

399. Additionally, the Commission proposed to retain the practice of masking the identity of participants when releasing offer and bid data. The Commission further proposed that the RTO or ISO include in its compliance filing a justification of its policy regarding the aggregation or lack thereof of offer data and of cost data, discussing the manner in which it believes its policy avoids participant harm and the possibility of collusion, while fostering market transparency.

ii. Comments

400. Commenters in general support information sharing policies for MMUs,[482] and many commenters noted that the Commission struck a good balance between the need for information and the limitations of the MMUs.[483]

401. Several commenters generally support the approach of developing the types of material to be disseminated on a case-by-case basis.[484] EEI supports this flexible approach as long as the information is developed in the ordinary course of business by the MMU and is subject to the same confidentiality restrictions that are applied to release of information as determined by each RTO or ISO, or the Commission.[485] Midwest Energy comments that as regulators of retail markets, state commissions should be aware of how the market is functioning.[486] New York PSC states that the Commission should clarify that its proposed rule is the minimum standard for the dissemination of information and the MMUs that currently provide information to state commissions under working procedures will not be limited by the proposal.[487]

402. APPA does not oppose this proposal but comments that a provision like the one in PJM's tariff, which allows the MMU to respond to requests for studies or reports by states, should be included in all RTO/ISO/MMU tariff sections.[488] PG&E believes that to the extent that state commissions need information about markets and market monitoring reports, it should be made clear that if the MMUs have data available as part of their overview of markets or preparation of reports, such data should be made available to state commissions for their use in analysis and oversight of market efficiency and trends.[489] Joint Commenters support an evaluation of the type of data each RTO or ISO should provide, stating that RTOs and ISOs can further improve their markets by describing in their compliance filings additional information they will disseminate.[490] Joint Commenters urge the Commission to require each RTO or ISO to engage in a stakeholder process to develop a detailed document governing the identification of the type of additional information the RTO or ISO will disseminate, and to describe the information to be disseminated in the compliance filing. Joint Commenters recommend that the Commission require each RTO or ISO to apply the following criteria: (1) RTOs and ISOs should provide information to the extent it reasonably can be expected (a) to facilitate improved market transparency, reliability or efficiency; (b) to assist stakeholders in detecting market design or software flaws and/or suspected market manipulation; or (c) to assist market participants in their transaction activity; (2) provided that (a) the dissemination of the information will not harm the competitive dynamics

[482] *See, e.g.*, DC Energy; EEI; EPSA; Exelon; NEPOOL Participants; and Northeast Utilities.

[483] *See, e.g.*, EEI; EPSA.

[484] *See, e.g.*, EEI; FirstEnergy; Midwest Energy; Ohio PUC; and PJM Power Providers.

[485] EEI at 26.

[486] Midwest Energy at 4–5.

[487] New York PSC at 10.

[488] APPA at 87.

[489] PG&E at 20.

[490] Joint Commenters at 5.

of the market and (b) it is feasible from a resource allocation standpoint for the RTO to disseminate the information.[491]

403. NARUC believes that the Commission's proposal is a mistake, commenting that the Commission should provide explicit standards that assure that the states have the same access to data as does the Commission.[492] NARUC comments that (1) by granting such access, the Commission can leverage market oversight while, as explicitly acknowledged in the NOPR, giving state regulators access to data they need to fulfill their statutory responsibilities; (2) states need underlying data imbedded in aggregate information to verify and analyze MMU findings; and (3) states also recognize the need to protect from public disclosure information that could harm market participants or facilitate collusion.[493]

404. Commenters support the proposal to include market participants in the dissemination of reports.[494] NRECA, while supporting the proposal, is concerned that these reports may be insufficient if they do not provide the underlying data and assumptions used by the MMU to reach its conclusions, on the ground recipients may only be getting the RTO's or ISO's ''spin'' on the situation. NRECA suggests that the Commission should ensure the MMU reports provide sufficient information or provide a process whereby stakeholders can obtain access, subject to appropriate confidentiality restrictions, to the data and findings underlying MMU reports.[495] NSTAR strongly supports including market participants in the dissemination of information on market abuses, and states that the reporting should be transparent as a deterrent and so market participants can assess how well the markets are working and whether changes are necessary.[496]

405. Several commenters do not support the Commission's proposal to limit access by market participants to conference calls.[497] APPA recommends that conference calls be archived and posted on the RTO or ISO Web site for market participants who cannot be on the call.[498] Steel Producers and TAPS comment that the exclusion of market participants from such conference call is inappropriate, and that RTO or ISO stakeholder conference calls with numerous participants are commonplace.[499]

406. Commenters generally supported the Commission's proposal and conclusions regarding quarterly and state of the market reports.[500] APPA comments that certain annual state of the market reports are both over-inclusive with the amount of data reported and under-inclusive in terms of relevant data provided, and that MMUs should strive for quality as well as quantity in the data provided. EPSA supports the Commission's conclusion that the quarterly reports should not be as extensive as the annual state of the market reports.[501]

407. Most commenters supported the reduction in lag time for offer and bid data to three months.[502] Several others wanted a shorter lag time: one month,[503] one week or less,[504] or immediate disclosure.[505] Several commenters suggested giving RTOs and ISOs flexibility to propose shorter or longer times.[506] Citing two studies, APPA argues that system lambdas should be disclosed at the same time as bid and offer data.[507] If the Commission requires a shorter period of time to release offer and bid data, EEI argues it should maintain and enhance the masking and aggregation features.[508] Although it supports the three-month period, Midwest ISO prefers leaving the decision to the stakeholders.[509]

408. PG&E states that it is important that information about offer and bid data be increasingly available as prices and price caps rise, with disclosure of bid data sufficiently timely to permit review of bids before the necessity to undertake any challenge to such sales. PG&E also states that there is a need for increased market transparency when prices hit established bid or price caps, as such bidding may be designed to manipulate market prices and take advantage of temporary conditions. PG&E requests the Commission to consider modifying its disclosure requirements to provide for greater market transparency for bids at caps, with discretionary authority to disclose participants who bid in the region of any applicable price cap.[510]

409. TAPS proposes immediate disclosure, arguing that competitive markets thrive on information, not secrecy. More information in the hands of a larger number of competitors, in its opinion, would reduce the likelihood of collusion. TAPS cites competitive electric markets operating successfully in Australia, England and Wales, where the markets provide near real-time and historical data, including bid and offer data. TAPS also asserts that large generation-portfolio holders already know their offers for each of their multiple resources, and allowing RTOs or ISOs to make it available for free and more quickly would enable smaller market participants to compete on a level playing field and assist with market monitoring.[511]

410. A few commenters opposed the Commission's proposal to reduce the lag time from six to three months.[512] Ameren states that six months is a more appropriate time period to protect commercially sensitive data and guard against abuse.[513] Constellation does not support the reduction in lag time for release of information, but says if the Commission decides to do so, it should apply this policy to all areas of the market and require MMUs to post bid and offer data for demand and virtual markets under the same confidentiality provisions.[514] Ohio PUC states that the entities most likely to use the data are the market participants themselves, and believes there is little protection offered by masking the bidders' identities. It agrees with the Commission's analysis of the tradeoffs in reducing the lag period.[515]

411. All but two commenters support masking participant identity.[516] Ameren emphasizes the need to protect sensitive

[491] *Id.*

[492] NARUC at 13–14.

[493] *Id.*

[494] *See*, *e.g.*, APPA; California PUC; Midwest ISO; Old Dominion; and NSTAR.

[495] NRECA at 54–55.

[496] NSTAR at 8.

[497] *See*, *e.g.*, APPA; Steel Producers; and TAPS.

[498] APPA at 88.

[499] Steel Producers at 12; TAPS at 57.

[500] *See*, *e.g.*, EPSA; California PUC.

[501] EPSA at 14–15.

[502] *See*, *e.g.*, EEI; California PUC; Industrial Consumers; ISO New England; Joint Commenters; Midwest ISO; North Carolina Electric Membership; NRECA; Reliant; SCE-SDG&E; and SPP.

[503] Industrial Consumers at 23.

[504] TAPS at 53–56.

[505] APPA at 89–91.

[506] EEI at 26–27 (citing regional factors); California PUC at 44; Joint Commenters at 4; and North Carolina Electric Membership at 19 (citing the need to prevent collusion); National Grid at 9; and SoCalEdison-SDG&E at 4.

[507] APPA at 89–91 (citing McCullough and Stewart, Ann, *The Missing Benchmark in Electricity Deregulation,* McCullough Research (Dec. 20, 2007); Dunn, William, *Data Required for Market Oversight—A Concept Paper for the Electric Market Reform Initiative of the American Public Power Association,* Sunset Point LLC (Dec. 8, 2007) (Dunn Study)).

[508] As an example, bid data should be aggregated in categories of size and the coding used to describe bidders should be changed periodically. EEI at 26–27.

[509] Midwest ISO at 28–29.

[510] PG&E at 20–22.

[511] TAPS at 53–56 (citing the Dunn Study).

[512] *See, e.g.*, Ameren; Constellation; and Ohio PUC.

[513] Ameren at 36.

[514] Constellation at 17.

[515] Ohio PUC at 28.

[516] *See, e.g.*, Ameren; California PUC; Dominion Resources; EEI; ISO New England; Midwest ISO; SoCalEdison and SDG&E; and SPP.

market data.[517] Dominion Resources and EEI oppose unmasking, Dominion Resources stating that masking is needed to avoid the possibility of bid or offer fixing, collusion, or other behavior detrimental to the market.[518] California PUC suggests unmasking after two years; it also proposes to change masking on January 1 of each year to prevent market participants from being able to figure out the market participants in current data.[519] SPP requests guidelines from the Commission on aggregating the data to protect the participant's identity.[520] Ameren proposes a mechanism where MMUs could give parties who have submitted false or inaccurate data the opportunity to correct any inaccuracies before the report is made final and submitted to the Commission.[521]

412. Two commenters oppose masking bidders' identities. Ohio PUC and OMS believe there is little protection offered by such masking, arguing that the more sophisticated market participants will infer those identities and thus gain some further advantage over less sophisticated market participants. These commenters further assert that allowing third-party analysts to access data would increase the number of parties examining the bid and offer data to determine if collusive behavior exists.[522] APPA states that market bid and offer data should not be kept confidential, and the term ''commercially sensitive'' should not be used as a blanket exception.[523]

iii. Commission Determination

413. We adopt the proposal made in the NOPR, with certain modifications. The Commission's goal of broadening information sharing by the MMUs met with widespread approval, with a number of commenters expressing the opinion that the Commission had struck the right balance between the need for information on the one hand while recognizing the MMUs' inability to provide unrestricted and unlimited amounts and types of information on the other.

414. The information to be disseminated should consist of market trends and the performance of the wholesale market, with details to be developed on a case-by-case basis. In response to our request for comments on whether there were a generic standard or test that could be used to determine what specific information should be provided to state commissions, Joint Commenters propose a two-part test, which we find generally helpful. However, the test does not include some of the confidentiality protections we have determined to be necessary, and we decline to adopt it. We also hesitate to require RTOs and ISOs to include in their tariffs specific details of the types of information that an MMU might find useful to provide, or that stakeholders might request. The nature of the information that may be helpful may vary from region to region, and may well evolve over time. Therefore, while an RTO or ISO is free to propose in its tariff details of the information it desires its MMU to provide, we will not require any particular menu. We are confident that MMUs will be responsive to reasonable requests from interested parties, subject to time and resource commitments.

415. Moreover, the degree of inclusion of underlying data and assumptions is an area also best dealt with on a case-by-case basis. It is not to be expected that MMUs would include all the raw data in their possession. However, we would expect that they would provide, or make available on request, sufficient data to enable users of their reports to reasonably test the validity of their conclusions.

416. We also clarify that our proposed rule is not intended to limit existing arrangements between MMUs and state commissions regarding the provision of information, subject to appropriate restrictions related to confidentiality concerns. Such arrangements are an example of the sort of case-by-case determination we envision developing in the area of information dissemination.

417. We disagree with NARUC's suggestion that explicit standards be put in place guaranteeing that states have the same access to data as does the Commission. While we favor the enhanced dissemination of information to the states, there are some matters that are uniquely within the purview of the Commission, such as referrals by MMUs of suspected tariff violations or manipulation. We therefore decline to adopt such explicit standards.

418. We agree with EPSA that quarterly reports should not be as extensive as the annual state of the market reports. It was not our intention that MMUs should be required to spend all their time on report preparation, which could easily be the case if quarterly reports were too extensive. Rather, we envision such quarterly reports as serving the function of timely updates to the annual state of the market report, emphasizing issues of concern. The details of what should be included in these reports can be worked out by the MMUs with input from interested stakeholders. We also agree with APPA that quality rather than quantity is crucial, and urge MMUs to ensure that the data they include in both their quarterly and their annual reports meets the anticipated needs of the extended community that will make use of them.

419. Several commenters object to the Commission's suggestion that market participants be excluded from conference calls regarding market updates. They note that stakeholder conference calls are commonplace, and see no reason why a similar practice should not be adopted with respect to MMU briefings. Upon reflection, we agree that the current state of the technology permits such calls with little difficulty. Therefore, we determine that market participants should not be excluded from such calls, absent pressing technical concerns in any given situation.

420. Our proposal to reduce the lag time for release of offer and bid data to three months was supported by most commenters. Some commenters requested a shorter lag time or immediate release. Others proposed the release of additional information, such as system lambda.

421. Our proposal cuts the current lag time for most RTOs and ISOs in half. Because this is a substantial change, RTOs and ISOs should become accustomed to the new release time and observe its effects before committing to an even shorter time. However, as we proposed in the NOPR, we permit the RTOs and ISOs to propose a shorter time, with accompanying justification, or a longer time of four months if they can demonstrate a collusion concern. Alternatively, they may propose an alternative mechanism if release of a report were otherwise to occur in the same season as reflected in the data. These options provide the flexibility requested by commenters.

422. We assume the data to be released would consist not only of physical offers and bids but demand and virtual offer and bids as well. However, if RTOs and ISOs object to such inclusion, they may address it in their compliance filings. Likewise, if they desire to release additional data such as system lambda, they may propose it in their filings.

423. We adopt the NOPR proposal to retain the masking of identities. The objection that sophisticated market participants may be able to infer identities of those submitting offers and

[517] Ameren at 36.

[518] Dominion Resources at 8; EEI at 26.

[519] California PUC at 44.

[520] SPP at 9.

[521] Ameren at 36–37.

[522] Ohio PUC at 28; OMS at 9–10.

[523] APPA at 93.

bids does not resolve confidentiality concerns; if anything, it argues for more protection, rather than less. We decline to establish a time period for the eventual unmasking of identities, but invite RTOs and ISOs to propose a period when such unmasking might be permitted, if they believe it to be desirable.

424. We therefore adopt the proposals advanced in the NOPR, modified as indicated. Each RTO and ISO is to include in its tariff a requirement that the MMU is to prepare an annual state of the market report on market trends and the performance of the wholesale market, as well as less extensive quarterly reports, all of which are to be disseminated to Commission staff, to staff of interested state commissions, to the management and board of directors of the RTOs or ISOs, and to market participants, with the understanding that dissemination may be accomplished by posting on the RTO's or ISO's Web site. MMUs are also to make one or more of their staff members available for regular conference calls, which may be attended, telephonically or in person, by Commission and state commission staff, by representatives of the RTO or ISO, and by market participants. The information to be provided in the MMU reports and in the conference calls may be developed on a case-by-case basis, but is generally to consist of market data and analyses of the type regularly gathered and prepared by the MMU in the course of its business, subject to appropriate confidentiality restrictions. We also determine that the lag time for the release of offer and bid data be reduced to three months; however, an RTO or ISO may propose a shorter period with accompanying justification. Furthermore, if the RTO or ISO demonstrates a potential collusion concern, it may propose a four-month lag period or, alternatively, some other mechanism to delay release of the data if it were otherwise to occur in the same season as reflected in the data. The identity of market participants is to remain masked, although the RTO or ISO may propose a time period for eventual unmasking. The RTO or ISO is to include in its compliance filing a justification of its policy regarding the aggregation or lack thereof of offer data and of cost data, discussing the manner in which it believes its policy avoids participant harm and the possibility of collusion, while fostering market transparency.

b. Tailored Requests for Information

i. Commission Proposal

425. In the NOPR, the Commission carried forward the ANOPR proposal allowing state commissions to make tailored requests for information from MMUs regarding general market trends and performance, not to include information designed to aid state enforcement actions against individual companies. The Commission also proposed that a state commission could, on a case-by-case basis, request the Commission to authorize the release of otherwise proscribed data, if the state commission demonstrated a compelling need for the information and could insure adequate protections for commercially sensitive material. The Commission proposed that before an MMU be allowed to release information pertaining to a particular market participant, that the participant be given the opportunity to object and to correct any inaccurate information proposed to be released, and that the availability of this protection be included in the RTO or ISO tariff. The Commission also proposed that RTOs and ISOs develop, and include in theirtariffs, confidentiality provisions that would protect commercially sensitive material, but which would not be so restrictive as to permit the release of little if any information.

ii. Comments

426. Several commenters generally support the Commission's proposal regarding tailored requests for information.[524] APPA comments that the Commission should not bar MMUs from providing such assistance to the states if MMUs believe they can do so without harming their own mission.[525] ISO New England states it has an information policy that already allows it to release confidential market information to state commissions under certain circumstances and subject to non-disclosure protections.[526] Duke Energy is concerned with giving the MMUs too much discretion and potentially imposing an unreasonable burden on them, but states that the guiding parameters set out by the Commission make the proposal more acceptable.[527] FirstEnergy states the MMU should share analyses and information with state commissions only when directly necessary to support state regulatory obligations, and agrees that tailored requests from state commissions should not detract from the MMU's core duties and must be made in light of budget and time limitations.[528]

427. The California PUC agrees that requests by state commissions should not overly burden the MMUs but comments that this need not be the case, noting that in California, CAISO and the California PUC have been able to work out the wording, scope and timing of the California PUC information requests in a reasonable and cooperative manner, including the protection of sensitive commercial information with a nondisclosure agreement. The California PUC and PG&E also comment that the MMU's core function of reviewing and reporting on the performance of wholesale markets should be understood to include reporting to state commissions, and assert that data used in making MMU assessments of market efficiency or competitiveness, reports to CAISO management or boards, or reports to the Commission should be available to state commissions as well.[529]

428. EEI and Reliant support allowing the MMUs to be receptive to requests for information, as long as the information pertains to market trends and is developed in the ordinary course of business. EEI and Reliant comment that it is not reasonable for the MMUs to provide new studies or analysis beyond their annual and quarterly reports, and assert that state commissions may not treat MMUs as private consultants to perform studies. These commenters also assert that states have their own enforcement programs and should not rely on the MMU. Reliant suggests that, if a state commission requesting MMU information cannot agree with the RTO's or ISO's confidentiality provisions, the Commission should clarify that the MMU should not be required to disclose information to the state commission.[530]

429. The Kansas CC agrees with the Commission's proposal not to require MMUs to provide information to aid in state enforcement efforts or actions against individual utilities. However, it suggests that sensitive market information could be provided to state commissions in a manner that would uphold the confidential nature of the information and protect the market. The Kansas CC requests that the Commission consider alternative solutions that will preserve confidentiality, while providing state commissions with

[524] *See, e.g.*, PJM Power Providers; SoCalEdison-SDG&E.

[525] APPA at 92–93.

[526] ISO New England at 26.

[527] Duke Energy at 11.

[528] FirstEnergy at 16.

[529] *See, e.g.*, California PUC; PG&E.

[530] *See, e.g.*, EEI; Reliant.

information necessary to fulfill their statutory and regulatory charges.[531]

430. The Ohio PUC, noting the interconnectedness of retail rates to wholesale markets, proposes a test to determine the type of information that should be disseminated to state commissions. In its view, if a state commission asks for it, and the MMU has it or can get it without undue burden, it should be provided subject to confidentiality provisions.[532]

431. Several commenters do not support various aspects of the Commission's proposal on tailored requests from state commissions. The California PUC contends that the restrictions would cripple state market monitoring, and asks the Commission how it would distinguish between information designed to aid state enforcement actions from information designed to allow states to monitor the market.[533]

432. NARUC states that imposing the proposed limitations on state access to information is inefficient and unnecessary, observing that states operate in the public interest. NARUC argues that requiring unnecessary proceedings over specific requests, at taxpayer or ratepayer expense, is not good policy, and asserts that state commissions have demonstrated their ability to maintain the integrity of commercially sensitive materials.[534]

433. The New York PSC states that limiting its ability to obtain such information is unnecessary and unsupported by the record in this proceeding, contending that the Commission has not demonstrated that providing information to state commissions for state enforcement purposes violates any provision of law or policy, and noting that the purpose of the information may not be apparent in any event. It suggests that in the event the MMU is concerned about budgetary and time limitations, it could simply provide the state commission with the raw data and allow the state commission to employ its resources to derive the information or analysis sought. It proposes that if a state commission is able to maintain the information on a confidential basis, the MMU should be allowed to determine whether to provide the requested information.[535]

434. OMS disagrees with the Commission that its proposed restrictions on information access by state commissions are reasonable. It asserts that the NOPR proposal limiting state commission requests to the MMU to ''general market trends and performance'' represents a significant reduction in the information its members already receive in accordance with the Midwest ISO's tariff. OMS states that the Commission should respect the arrangement currently in place for the Midwest ISO, and permit that arrangement to be expanded, as necessary, to meet the need of OMS and its state commission members. OMS also asserts that state commissions should not be put in a position of merely having to trust the findings of the MMU, but rather, should be provided with the data and information necessary to evaluate and verify the MMU's findings. It also states that the Commission's proposal to prohibit state commissions from seeking information from the MMU that would aid state enforcement is unreasonable, as many state commissions do not have access to the data and information necessary to initiate investigative actions that might eventually lead to enforcement actions.[536]

435. Other commenters provided suggestions and points of clarification. The FTC encourages the Commission to devise ways that would allow MMUs to provide services to state and federal agencies even when the MMU does not have the extra resources. For example, it suggests that the Commission could authorize fees to be paid by state and federal agencies for services that primarily assemble and organize existing MMU data, which is similar to how other agencies deal with FOIA requests.[537] The California PUC comments it is unclear if ''information regarding general market trends and performance'' would be limited to aggregated data or if the state commissions would also have access to raw data. It also states that this proposal would restrict existing access to data, and would require states to obtain Commission authorization and make a showing of a ''compelling need'' for that information.[538] CAISO states that the Commission should clarify whether its proposal applies only to requests or also to subpoenas and court orders.[539] TAPS opposes giving state commission staffs preferential treatment in the ability to make requests for information from the MMU.[540]

436. Several of the commenters support the provision regarding the development of confidentiality provisions, with limitations. The California PUC asserts that the language is too vague, and suggests it be revised to read ''The RTO should develop confidentiality provisions in their tariffs that will protect commercially sensitive material, but will be no more restrictive than necessary to protect that information.'' The California PUC also notes that the California PUC and CAISO have an established practice for sharing market information that preserves confidentiality of data, and argues that the proposed limitations are unnecessary and would disrupt already existing state access to market data.[541]

437. The Maine PUC stresses the need for a greater level of information sharing by ISO New England with state commissions. It proposes that where there are protections in place to ensure that confidential information remains confidential when disclosed to a state commission, the Commission should direct ISO New England to share confidential information with the state commissions in the same or similar manner to its information sharing with the Commission.[542]

438. The Ohio PUC and PJM request clear rules and definitions relating to confidential information. The Ohio PUC states that the Commission should require RTOs or ISOs to revisit the definitions of ''Confidential Information'' in their tariffs, asserting that in the cases of PJM and the Midwest ISO, confidential information is whatever a market participant declares it to be. PJM is concerned about the treatment of confidential information, such as cost data, particularly in the area of aggregated data that may be ''reverse engineered.'' PJM states that the release of these data, in conjunction with other industry information not necessarily known or even available to PJM, could inflict commercial harm on a market participant and adversely impact the competitiveness of the market. PJM requests clear, bright-line rules regarding the treatment of confidential information, noting it must deal with large volumes of such information that frequently are the subject of requests from numerous public and private entities.[543]

439. Reliant and SPP are concerned about the treatment of confidential materials once in the hands of the state commissions. Reliant is of the view that

[531] Kansas CC at 2.

[532] Ohio PUC at 27, 29.

[533] California PUC at 48–49.

[534] NARUC at 15.

[535] New York PSC at 10–12.

[536] OMS at 13–14.

[537] FTC at 31.

[538] California PUC at 47–48.

[539] CAISO at 16–17.

[540] TAPS at 57.

[541] California PUC at 46, 49.

[542] Maine PUC at 8–9.

[543] *See, e.g.*, Ohio PUC; PJM.

state commissions should be required to identify the person who will have access to the information, the person who will be the official custodian for the information, and the purpose for the request. It states that a state official should be required to sign a non-disclosure agreement as a pre-condition of receiving data and, in situations where the state cannot guarantee data confidentiality, such as in the case where a state's public records regulations might require disclosure, such data should not be shared. SPP is concerned that unless the state commission can provide proof that information can and will be kept confidential, that SPP should not be required to provide that information to the state commission, and asks that the Commission address the issue of relieving the RTO or ISO from any liability.[544]

440. PJM Power Providers states that given the serious potential consequences associated with an improper release of sensitive market data, the Commission should go to great lengths to ensure the confidentiality of this information.[545]

441. Commenters generally agree with the proposal to permit market participants the opportunity to contest any data specific to them that the MMU proposes to release. Duke Energy supports allowing market participants an opportunity to contest information, but comments that market participants should also have an opportunity to respond to data and not just contest them, as they may want to provide context to data even if they do not wish to dispute them.[546] FirstEnergy agrees that affected utilities should be given notice and have the opportunity to comment.[547]

442. Several commenters support the Commission's proposal to allow state commissions to request release of data from the Commission, with limitations or additions. EEI supports the Commission releasing data if the state demonstrates a compelling need and cannot obtain the data from any other source, and if the Commission can adequately protect commercially sensitive data.[548] APPA believes that state entities (including commissions, state attorney generals, legislators, governors, and relevant electric retail regulatory authorities for public power systems) and third parties should be allowed to request information on a case-by-case basis directly from an MMU; if the MMU believes it can provide the needed information it should not have to go through the Commission, and only in the event the requestor is refused the information by the MMU, would it be necessary to petition the Commission.[549] Duke Energy comments that affected market participants should have recourse to appeal an MMU decision to the Commission, just as a requester can petition the Commission.[550]

443. Other commenters strongly oppose the Commission's proposal regarding submitting a request for the release of otherwise proscribed information. NARUC believes the proposal is likely to hamper proper state oversight, and argues that the Commission should not impose a gatekeeper function to evaluate state commission information needs or the legitimacy of their requests. NARUC argues this can only waste both state and federal resources and ratepayer funds on unnecessary proceedings.[551]

444. The Ohio PUC questions how enforcement can occur without access to market information, which it argues the Commission currently controls. It asserts that the Commission must reevaluate its position on this matter to ensure that state commissions have timely access to market information and possess all the necessary tools to make certain that customers' interests are protected against market abuses and manipulation. It also suggests that it could take entity-specific information subject to a confidentiality agreement, and then use that information to pursue its own discovery under state law, in order to pursue an enforcement action.[552] OMS states that state commissions should not be required to petition the Commission for access to data and information that it feels should be theirs in the first place. OMS strongly urges the Commission to reconsider its position in this regard.[553]

445. OPSI does not agree with the Commission's proposal and recommends that any rules adopted in this proceeding reflect the data availability practices established in the PJM/MMU Settlement Agreement.

iii. Commission Determination

446. The enhanced information sharing provisions we adopt in this Final Rule significantly expand the materials that state commissions may receive. However, we are cognizant that state commissions might from time to time desire additional information pertinent to their particular needs. Therefore, we adopt the NOPR proposal that state commissions may make tailored requests for information from the MMUs, so long as the request is limited to information regarding general market trends and the performance of the wholesale market. This limitation is needed in light of the limited resources of the MMUs, whose first order of business is evaluating market design, monitoring the markets, and referring suspected wrongdoing to the Commission. If this limitation were not imposed, the MMU could rapidly become an unpaid consultant for the states, and would be unable to perform its core functions.

447. We are cognizant of the observations by EEI and Reliant that state commission requests for information, which would necessarily be in addition to the information already produced in the MMUs' annual and quarterly reports, may place an unreasonable burden on the MMUs. We therefore direct that the MMUs, in the first instance, determine whether a request would be unduly burdensome. If so, it need not perform the requested study.

448. Many comments centered on the need for the confidentiality of the materials provided by the MMU, and the means by which confidentiality concerns could be addressed. Inasmuch as the material to be provided in response to tailored requests for information will consist of market trends and the performance of the wholesale market, such confidentiality concerns may not prove to be as great a stumbling block as some suggest. Where information to be provided raises confidentiality concerns, the information may nonetheless be provided, if appropriate non-disclosure agreements are executed. We direct the RTOs and ISOs to develop confidentiality provisions for their tariffs, and adopt the California PUC suggestion that such provisions be designed so as to protect commercially sensitive material, but be no more restrictive than necessary to protect that information. It will be up to each RTO or ISO, together with its stakeholders, to propose the confidentiality provisions they deem most appropriate, and to propose them to the Commission in a tariff filing.

449. We note that our directive regarding the ability of state commissions to make tailored requests for information is designed to increase the dissemination of information, not

[544] *See, e.g.*, Reliant; SPP.

[545] PJM Power Providers at 18.

[546] Duke at 11–12.

[547] FirstEnergy at 16.

[548] EEI at 28.

[549] APPA at 94.

[550] Duke at 12.

[551] NARUC at 15–16.

[552] Ohio PUC at 35.

[553] OMS at 14–15.

restrict it. As we have indicated elsewhere, the type of information to be provided by the MMU may vary from region to region, and is governed principally by the workload such requests impose on the MMU. Therefore, unless the information violates confidentiality restrictions regarding commercially sensitive material, is designed to aid state enforcement actions, or impinges on the confidentiality rules of the Commission with regard to referrals, it may be produced, so long as it does not interfere with the MMU's ability to carry out its core functions.

450. We decline to require MMUs to turn over raw data if they do not have the time to comply with a tailored request for information. If the MMU determines that raw data may be provided, appropriately redacted to meet confidentiality concerns, it may do so. However, it is quite possible that gathering, organizing, reviewing, and explaining such data might prove nearly as time consuming as responding in a narrative fashion to a request for information. The MMU is not a consultant for the states, and should not be placed in the position of having to respond to every request for information submitted to it.

451. We also decline to eliminate our restriction on the state commissions' ability to request information designed to aid state enforcement actions. Of course, if a state receives information regarding general market performance, and chooses to pursue a more focused study with its own resources, there is no prohibition to its doing so. The key considerations here are the burden placed on the MMU, the nature of the material to be provided, and the need for confidentiality. The MMU will be in the best position to determine if the material requested would be unduly burdensome to produce. And the RTO or ISO confidentiality provisions, as well as those of the Commission, will govern whether the state commission can receive information of a confidential nature.

452. A state commission need not turn an MMU into an arm of its investigatory processes in order to carry out its duties. If a state has information suggesting the need for an investigation, it can use the full panoply of its powers and resources to pursue the matter on its own. We know from long experience that investigations are very time and resource-intensive, and were states to enlist the MMU's assistance in this regard, it would leave the MMU with little ability to carry out its core functions.

453. We note, however, that from time to time Commission staff investigates matters of mutual interest to state commissions. It has been staff's practice to work cooperatively with the states in such cases, bearing in mind the confidentiality of materials obtained by Commission staff in the course of an investigation. We direct staff to continue its practice in this regard.

454. Whether requested information is designed to aid an enforcement action can generally be answered by the particularized nature of the request and the extent of the questions. As we have stated, the information to be provided in response to a tailored request for information should consist of market trends and the performance of the wholesale market. At least one comment reinforces the need for caution in this regard. The comment suggested that a state body could take entity-specific information subject to a confidentiality agreement and then use that information to pursue its own discovery. This end run around the confidentiality provisions might raise liability concerns on the part of both the MMU and the RTO or ISO, and possibly the Commission itself, and underscores the need to be sensitive to requests designed to support enforcement actions.

455. We adopt the NOPR proposal that market participants be given the opportunity to contest any data specific to them. We also adopt the proposed expansion of this provision to include the right to provide context to the data, so long as the process does not unduly delay release of the information.

456. CAISO asks that we clarify whether our proposal applies only to requests or also to subpoenas and court orders. We clarify that our proposal applies to requests. Whether subpoenas or court orders are to be honored or contested lies outside the scope of this Final Rule and is a matter to be addressed by the MMU and by the RTO or ISO, in consultation with their attorneys.

457. We decline to adopt the FTC's suggestion that state and federal agencies be given the ability to obtain data from the MMU through the payment of fees. Such a fee arrangement could raise conflict of interest concerns. More significantly, however, it would reduce the MMU to the position of a consultant for hire, a role which would necessarily distract it from its core functions.

458. We also adopt our NOPR proposal permitting state commissions to petition the Commission for the release of otherwise proscribed information. This provision is intended as a safety net to increase the ability of states to receive information, not as a further restriction. State commissions are free to direct their requests to the MMUs in the first instance, but such requests should comply with the restrictions we note above. If they do not, waiver of such restrictions is up to the Commission, not to the MMUs.

459. Therefore, we carry forward our proposal from the NOPR, modified as noted herein. MMUs are to entertain from state commissions tailored requests for information regarding general market trends and the performance of the wholesale market, but not for information designed to aid state enforcement actions. Granting or refusing such requests will be at the MMU's discretion, based on agreements worked out between the RTO or ISO and the states, or otherwise based on time and resource availability. Release of any confidential information is to be subject to the confidentiality provisions in the RTO's or ISO's tariff, and to the Commission's confidentiality restrictions. RTOs and ISOs are to develop confidentiality provisions that will protect commercially sensitive material, but which will be no more restrictive than necessary to protect that information. State commissions are also free to petition the Commission for the release of information that does not fall within the parameters noted. And market participants are free to contest the factual content of information to be released, or to provide context for it, so long as such material does not unduly delay release of the information.

c. Commission Referrals

i. Commission Proposal

460. In the NOPR, the Commission noted that its rules require that information regarding its investigations be kept nonpublic unless, in any given case, the Commission authorizes that it be publicly disclosed. We proposed that the existing provisions regarding the confidentiality of MMU referrals to the Commission, as well as the confidentiality of the progress and results of its own investigations, be retained. The Commission also noted that it intended to continue the practice of Commission staff providing the MMUs with generic feedback regarding enforcement issues.

ii. Comments

461. Several commenters support the Commission's proposal.[554] APPA also suggests that the Commission has the obligation to act as quickly as possible, so other government entities with a

[554] *See, e.g.*, APPA, EEI, Midwest ISO, Reliant, and SPP.

legitimate interest in the matter are kept informed.[555] ISO New England comments that the proposed referral provisions are generally consistent with, but more detailed than, ISO New England's existing rules concerning the obligation of its MMU to identify and report on market design flaws and to refer potential market manipulation to the Commission.[556]

462. Many commenters urge the Commission to reconsider its position that state commissions not be informed when an MMU refers a matter to the Commission.[557] Some commenters assert that several states maintain sufficient safeguards against public disclosure of information, and any assumptions regarding the potential mishandling of confidential information are misdirected and should be discounted.[558] The California PUC and NRECA comment that the Commission should provide information to the MMUs and state commissions about matters an MMU has referred to the Commission, because it would help increase confidence that the Commission investigates attempts to manipulate the market.[559] The Ohio PUC maintains that there must be a free exchange of market data among the RTO or ISO, the MMU, and state commissions to ensure markets are flourishing and to avoid manipulation.[560]

463. NARUC comments that the Commission should inform affected state commissions of MMU referrals because the commissions need information about specific market participants both to properly exercise their own regulatory authority and to avoid potentially inconsistent outcomes and duplicative efforts.[561] The New York PSC comments that it is vital that state commissions be able to demonstrate that the presence of a competitive market does not disable the state from protecting retail ratepayers, and that the state commission is capable of carrying out its statutory obligation in a competitive market.[562]

464. NRECA believes that an appropriate balance can be struck with respect to information and emphasized that it is not seeking the release of the names of individual entities or any competitively sensitive information but is merely requesting statistical information on, for example, numbers of entities referred, types of infractions, and the resolution of referrals.[563] OMS comments that state commissions could be effective allies with the Commission in the investigation and evaluation of the market participant behavior that led the MMU to make the referral, and the Commission's concern that informing state commissions of MMU referrals might discourage market participants from self-reporting objectionable behavior is not applicable to MMU referrals, as these referrals happen only because a market participant has failed to self-report.[564]

iii. Commission Determination

465. We adopt the NOPR proposal retaining the confidentiality of MMU referrals to the Commission, as well as the confidentiality of any investigations that result from such referrals. By Commission rule, all information and documents obtained during the course of an investigation are non-public. They may not be released except to the extent the Commission directs or authorizes in a given instance, unless the material is already made public during an adjudicatory proceeding or disclosure is required by the Freedom of Information Act.[565] There are sound policy reasons for this rule. As we noted in the NOPR, release of such confidential information would impede the willingness of market participants to cooperate in the investigation and to self-report in the future. It could also injure innocent persons who might be erroneously implicated or adversely affected by simply being associated with an investigation.

466. The Commission can only answer for its own abilities to keep material confidential, and cannot put itself in the position of having to interpret the extent of protections afforded by all the relevant state rules, statutes, and case law that govern disclosure. Nor can it expose itself to the potential liability it might incur by turning over confidential materials, should such materials be misused by agencies or individual state employees over whom the Commission has no control.

467. We also are not persuaded that release of information about MMU referrals would avoid potentially inconsistent outcomes and duplicative efforts. For that to be true, one would have to assume that the scope of jurisdiction and the governing laws of the states in question are identical to those of the Commission, which is clearly not the case.

468. We are sympathetic to NRECA's request for statistical information, and agree that, to the extent we can make our enforcement actions more transparent, it is desirable to do so. To that end, we recently announced that the staff of the Office of Enforcement will prepare and publicly release annual reports summarizing its enforcement activities for the preceding year, to be released at the close of our fiscal year, September 30.[566] The first such report was released on November 14, 2007.[567] In addition, it is the practice of Commission staff to provide the MMU with generic feedback regarding enforcement issues, and we will ensure that staff continues to do so.

469. We therefore decline to alter our rule and policy regarding the confidential nature of MMU referrals to the Commission.

4. Pro Forma Tariff

a. Commission Proposal

470. In the NOPR, the Commission declined to propose a *pro forma* tariff for the MMU sections of an RTO or ISO OATT, instead proposing that RTOs and ISOs conform their tariffs to the requirements set forth in this Final Rule. The Commission also proposed that each RTO or ISO include protocols for the referral of tariff, rule, and market manipulation violations to the Office of Enforcement, and for the referral of perceived market design flaws and recommended tariff changes to the Office of Energy Market Regulation.

b. Comments

471. A limited number of entities filed comments on the Commission's proposal. The Midwest ISO agrees that requiring each RTO or ISO to conform its tariff to the requirements of the Final Rule is preferable to a *pro forma* tariff.[568] EEI agrees that the Commission has appropriately permitted RTOs and ISOs flexibility to tailor their market monitoring provisions to their own regional variations.[569] APPA suggests that the Commission use, as a possible template for the relevant tariff provisions, the revised Attachment M to the PJM tariff approved in the PJM MMU Settlement Order.[570] SPP believes that it already complies with the majority of the proposals the

[555] APPA at 94.

[556] ISO New England at 27.

[557] *See, e.g.*, California PUC, NARUC, New York PSC, NRECA, Ohio PUC, and OMS.

[558] *See, e.g.*, New York PSC, Ohio PUC, and OMS.

[559] California PUC at 52–53.

[560] Ohio PUC at 32.

[561] NARUC at 16.

[562] New York PSC at 13–15.

[563] NRECA at 56.

[564] OMS at 11.

[565] 18 CFR 1b.9.

[566] *Revised Policy Statement on Enforcement,* 123 FERC ¶ 61,156, at P 12 (2008).

[567] Report on Enforcement, Docket No. AD07–13–000 (2007).

[568] Midwest ISO at 27.

[569] EEI at 24.

[570] *PJM MMU Settlement Order,* 122 FERC ¶ 61,257.

Commission has set forth in this proceeding, but will comply with any revisions that may be required by the Final Rule.[571]

472. The California PUC, on the other hand, states that it does not support a *pro forma* tariff because of its objections to several of the MMU proposals in the NOPR, particularly the issues surrounding state access to data.[572]

c. Commission Determination

473. Given the degree of discretion this Final Rule allows RTOs and ISOs to structure their relationship with their MMUs in the manner they deem most suitable, a *pro forma* MMU tariff section would be impractical. Therefore, we will not impose one.

474. We also decline to adopt PJM's MMU tariff section, Attachment M, as a template for a centralized MMU tariff section. That document is particularized to the needs of that RTO, and we therefore will not require other RTOs and ISOs to follow it. We agree, however, that some uniformity is desirable, particularly for market participants who operate in multiple regions, and for regulators who often have occasion to compare and contrast tariff provisions amongst the various RTOs and ISOs.

475. We therefore suggest, but do not require, that RTOs and ISOs consider structuring their MMU tariff sections to include the following general categories, preferably in this general order: Introduction and Purpose; Definitions; Independence and Oversight; Structure; Duties of Market Monitor; Duties of RTO or ISO; Data Access, Collection, and Retention; Information Sharing; Ethics; RTO- or ISO-Specific Provisions; Protocol on Referrals of Investigations to the Office of Enforcement; Protocol on Referrals of Perceived Market Design Flaws and Recommended Tariff Changes to the Office of Energy Market Regulation.

476. We note that in our Policy Statement on Market Monitoring Units,[573] we prescribed the form and contents of an MMU referral to the Office of Enforcement. We likewise include in this Final Rule updated protocols for such referrals, as well as protocols for referrals to the Office of Energy Market Regulation of perceived market design flaws and recommended tariff changes.

D. Responsiveness of RTOs and ISOs to Customers and Other Stakeholders

477. In this section of the Final Rule, the Commission requires RTOs and ISOs to establish a means for customers and other stakeholders to have a form of direct access to the board of directors, and thereby to increase the boards of directors' responsiveness to these entities. (By responsiveness, we mean an RTO or ISO board's willingness, as evidenced in its practices and procedures, to directly receive concerns and recommendations from customers and other stakeholders, and to fully consider and take actions in response to the issues that are raised.) The Commission requires each RTO or ISO to submit a compliance filing demonstrating that it has in place, or will adopt, practices and procedures to ensure that its board of directors is responsive to customers and other stakeholders. The Commission will assess each RTO's or ISO's filing using four criteria: (1) Inclusiveness; (2) fairness in balancing diverse interests; (3) representation of minority positions; and (4) ongoing responsiveness.

478. The Commission also directs each RTO and ISO to post on its Web site its mission statement or organizational charter. The Commission encourages each RTO and ISO to set forth in these documents the organization's purpose, guiding principles, and commitment to responsiveness to customers and other stakeholders, and ultimately to the consumers who benefit from and pay for electricity services.

1. Background

479. Neither Order No. 888 [574] nor Order No. 2000 [575] mandated specific RTO board governance requirements. In Order No. 2000, the Commission stated that, given the early stage of RTO formation, it would be counterproductive to impose a one-size-fits-all approach to governance when RTOs may have varying structures based on their regional needs.[576] Therefore, the Commission indicated that it would review governance proposals on a case-by-case basis.[577] The Commission also emphasized the importance of stakeholder input regarding both the creation of RTOs and ongoing operations.[578] The Commission added that, in the case of a non-stakeholder board, it is important that the board not become isolated.[579]

480. In the ANOPR, the Commission noted stakeholders' concerns that RTOs and ISOs are not sufficiently responsive to customers and other stakeholders, and that those parties should have some form of effective direct access to the RTO or ISO board of directors.[580] The Commission inquired whether RTOs and ISOs should be required to create and institute practices and procedures to ensure that customers and other stakeholders have such access.[581] The Commission also made a preliminary proposal that the goal of enhancing customer and other stakeholder access to the board could be achieved by either a board advisory committee or a hybrid board.[582]

2. Commission Proposal

Responsiveness Obligation and Proposed Criteria

481. In the NOPR, the Commission proposed to require that customers and other stakeholders have some form of effective direct access to the RTO or ISO board of directors. The Commission indicated that while it viewed the board advisory committee as particularly suitable for enhancing responsiveness, it anticipated that each RTO or ISO and its stakeholders would develop practices and procedures that best suit their needs.[583] The Commission reiterated its position that a one-size-fits-all approach may not be beneficial given the varying structure and needs of each regional entity. It therefore proposed to establish a set of four criteria for RTOs and ISOs designed to ensure that RTO and ISO

[571] SPP at 10.

[572] California PUC at 53.

[573] Policy Statement, 111 FERC ¶ 61,267 at Appendix A.

[574] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities,* Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g,* Order No. 888–A, FERC Stats. & Regs. ¶ 31,048, *order on reh'g,* Order No. 888–B, 81 FERC ¶ 61,248 (1997), *order on reh'g,* Order No. 888–C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group* v. *FERC,* 225 F.3d 667 (DC Cir. 2000), *aff'd sub nom. New York* v. *FERC,* 535 U.S. 1 (2002).

[575] *Regional Transmission Organizations,* Order No. 2000, FERC Stats. & Regs. ¶ 31,089 (1999), *order on reh'g,* Order No. 2000–A, FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd sub nom. Pub. Util. Dist. No. 1 of Snohomish County, Washington* v. *FERC,* 272 F.3d 607 (DC Cir. 2001).

[576] The Commission noted that existing ISOs have varying forms of governance. Some used a two-tier form of governance with a non-stakeholder board and advisory committees of stakeholders while one, CAISO, employed a decision making board consisting of both stakeholders and non-stakeholders. Order No. 2000–A, FERC Stats. & Regs. at 31,073.

[577] *Id.* at 31,073–74.

[578] *Id.*

[579] *Id.*

[580] ANOPR, FERC Stats. & Regs. ¶ 32,617 at P 148.

[581] *Id.* P 149.

[582] *Id.* P 151, 153. The Commission explained that a hybrid board would be composed of both independent members and stakeholder members, with each member holding a seat on the board and participating fully in board decisions with an equal vote. *Id.* P 152.

[583] *Id.* P 277.

boards are responsive to their customers and other stakeholders.[584]

482. In order to demonstrate that RTOs and ISOs meet the responsiveness obligation, the Commission proposed to require each one to submit a compliance filing showing that it has in place or will adopt practices and procedures to ensure responsiveness. The Commission proposed to assess the filed practices and procedures of each RTO and ISO using four criteria:

- Inclusiveness—The business practices and procedures must ensure that any customer or other stakeholder affected by the operation of the RTO or ISO, or its representative, is permitted to communicate its views to the RTO's or ISO's board of directors.
- Fairness in Balancing Diverse Interests—The business practices and procedures must ensure that the interests of customers or other stakeholders are equitably considered and that deliberation and consideration of RTO and ISO issues are not dominated by any single stakeholder category.
- Representation of Minority Positions—The business practices and procedures must ensure that, in instances where stakeholders are not in total agreement on a particular issue, minority positions are communicated to the RTO's or ISO's board of directors at the same time as majority positions.
- Ongoing Responsiveness—The business practices and procedures must provide for stakeholder input into the RTO's or ISO's decisions as well as mechanisms to provide feedback to stakeholders to ensure that information exchange and communication continue over time.

483. The Commission proposed that each RTO or ISO compliance filing would be required to be submitted within six months of the date the Final Rule is published in the **Federal Register**, and stated that it would assess whether each filing satisfies the proposed requirement and issue additional orders as necessary.[585]

3. Comments

484. Most of the commenters support the Commission's proposal and the four responsiveness criteria that the Commission proposed in the NOPR.[586] Many also express support for the Commission not proposing a one-size-fits-all solution, but instead allowing regions flexibility in meeting the criteria.[587] The comments fall loosely into three categories: (1) Whether to establish an obligation for responsiveness; (2) whether the four responsiveness criteria are appropriate or need greater specificity; and (3) whether additional criteria should be required.

485. Among the RTOs and ISOs, CAISO, Midwest ISO, NYISO, PJM and SPP argue that they already have responsiveness policies that they believe satisfy the Commission's proposed criteria. Some stakeholders concur that their RTO's or ISO's policies meet the proposed criteria.[588] APPA is skeptical that the proposals would have any effect, arguing that the RTOs and ISOs would likely say that their practices are already sufficiently responsive.[589]

486. Many commenters present examples of RTO or ISO practices that are not fully effective. For example, IID notes that during consideration of CAISO's proposal to subsidize the financing of certain interconnection facilities, CAISO did not adopt any of the specific tariff language IID recommended or sufficiently explain why it was rejecting so many of IID's suggestions.[590] TANC opines that time frames for stakeholder review of CAISO initiatives are too short and therefore appear to diminish the value of stakeholder input. As a result, TANC submits that the Commission should require RTOs and ISOs to employ methods of interacting with stakeholders that are intended to achieve consensus on issues and that incorporate stakeholders early in the decision-making process.[591]

487. Connecticut and Massachusetts Municipals encourage the Commission to not solely rely on an inclusive stakeholder process to ensure that organized wholesale electric markets and market administrators are providing, or facilitating the provision of, reliable electric service at the lowest reasonable cost. They do not agree that developing a stakeholder process that meets the four criteria will alleviate the need for the Commission to conduct its own investigation into the justness and reasonableness of proposed rates, charges, market rules, and design changes.[592]

488. Several commenters make recommendations about the four criteria proposed by the Commission. For instance, Ameren urges the Commission to make sure that the third criterion, representation of minority positions, is not allowed to outweigh the second criterion, fairness in balancing diverse interests. One way to do this, Ameren argues, would be to ensure that entities that will ultimately incur a major portion of the costs related to the changes to RTO or ISO market rules have a proportionate say in the development of these rules and any related modifications, through bicameral voting.[593]

489. TAPS asserts that the balancing criterion invites greater deference to well-represented classes to the detriment of other customers that the FPA requires the Commission to protect. CAISO requests that the Commission consider clarifying one of the four proposed criteria, fairness in balancing diverse interests, regarding how an RTO or ISO would be expected to establish generically that the consideration given to diverse interests is equitable.[594]

490. Constellation asks the Commission to clarify its definition of the term ''customer'' in its statement that ''access by customers and other stakeholders to the board based on these criteria will provide them with the opportunity to ensure that their concerns are considered.'' It states that the term customer could be applied to non-jurisdictional entities such as retail customers, and the Commission has already ensured that state agencies that regulate the retail market have access to RTO and ISO boards.[595]

491. Other commenters recommend more detail regarding the application of the proposed criteria. For example, APPA suggests new mandates for RTO and ISO stakeholder processes to help meet the proposed criteria:[596] Mandated direct stakeholder access to RTO and ISO boards at frequent intervals; presentation of minority positions on RTO and ISO proposals directly to the board by minority stakeholders; consideration of the use of both stakeholder advisory committees and hybrid boards; open RTO and ISO board meetings, with agendas made public in advance and opportunity for stakeholder comment on agenda items;

[584] NOPR, FERC Stats. & Regs. ¶ 32,628 at P 275.

[585] *Id.* P 92.

[586] *See, e.g.,* Ameren; Comverge; Constellation; EEI; Exelon; Indianapolis P&L; Midwest ISO; New York PSC; NYISO; PJM; and PG&E.

[587] *See, e.g.,* Ameren; ATC; Constellation; Midwest ISO; NYISO; PJM; and SoCal Edison-SDG&E.

[588] *See* Ameren and ATC discussing Midwest ISO; California PUC discussing CAISO; New York PSC discussing NYISO; and NEPGA, NEPOOL and NU discussing ISO New England.

[589] APPA at 9, 97.

[590] IID at 5.

[591] TANC at 12.

[592] Connecticut and Massachusetts Municipals at 9–10.

[593] Ameren at 15–16, 37–40.

[594] CAISO at 10.

[595] Constellation at 19.

[596] APPA at 10, 102.

elimination of ''self-perpetuating'' RTO and ISO boards; directors elected by stakeholder vote, with multiple candidates for each seat and stakeholder input into the slate selection; and administration of customer satisfaction surveys by outside entities. ATC wants a formalized mechanism within an RTO's or ISO's main stakeholder committee for communicating minority views of stakeholder sectors to an RTO's or ISO's board of directors.

492. SMUD states that RTOs and ISOs should be required to demonstrate that: (1) There is evenly divided industry sector representation, (2) no one sector (or entity) can dominate the process, (3) votes are taken to measure stakeholder sentiment, (4) there is a formal process for the RTO or ISO to consider adoption of stakeholder initiatives and (5) before the RTO or ISO can reject a stakeholder position supported by a supermajority of stakeholders, it must articulate its reasons in writing, including in any filing it makes with the Commission.[597]

493. Others suggest new criteria for improving responsiveness, such as providing opportunities for customer and other stakeholder feedback on budgets and costs. The Maine PUC argues that ISO New England has insufficient cost incentives, and that the Commission should consider requiring RTOs and ISOs to place a stronger emphasis on cost-containment in administration and development of wholesale electric markets.[598] North Carolina Electric Membership and NRECA suggest an additional criterion: Reliable service at just and reasonable rates. According to NRECA, the Commission's goals in creating RTOs and ISOs require that these entities ensure accountability to stakeholders for keeping costs down while maintaining a high level of service quality. NRECA also states that the Commission should require RTOs and ISOs to present annual budget information to customers and stakeholders, along with adequate detail, transparent assumptions and calculations of estimates, and cost support. It further recommends that the Commission require RTOs or ISOs with formula rates to develop their budget presentations for stakeholders and customers using the format required for a filing with the Commission to change previously approved rates. NRECA states that the RTO's or ISO's budgeting process should ensure that customers and other stakeholders have a timely opportunity for review of the budget proposals offered and that each RTO or ISO should submit to the Commission, as an informational filing, all of the budget materials provided to stakeholders for review.[599]

494. Ameren suggests that RTOs and ISOs should be required to post longer-term budgets, such as five-year budgets, so that market participants can better monitor the costs and benefits of participating in RTO and ISO Day 2 markets.[600] NRECA states that the NOPR is silent with respect to the matter of transparency in RTO and ISO budgets. Old Dominion also requests that the Commission reinstate the proposals contained in the ANOPR that would have improved transparency in the budget process.[601]

495. Some commenters ask for a formal cost-benefit review of any significant action. Connecticut and Massachusetts Municipals request that the Commission require RTOs and ISOs to perform cost-benefit studies in support of proposed rates, charges, and related rules. FirstEnergy also recommends that significant new RTO or ISO proposals should require a formal cost-benefit analysis before being submitted to the stakeholder process. If these proposals are implemented, they argue, post-implementation cost-benefit analyses should be employed to see if actual benefits have materialized. RTO or ISO initiatives that fail to produce stakeholder benefits or achieve their stated objectives should be modified, or if necessary, rescinded.[602] LPPC also suggests that the Commission should require cost-benefit analyses to be filed in conjunction with any significant capital expenditures or tariff changes. These cost-benefit analyses would be submitted with the annual budgets for approval by the Commission in the case of capital expenditures, or with section 205 filings for tariff changes.[603]

496. Other commenters want improvements regarding notice of meetings and time to review new proposals. TANC asserts that the Commission should set minimal standards as to what constitutes sufficient notice for convening stakeholder meetings and conference calls, for the submission of stakeholder comments, and for subsequent consideration of those comments prior to the RTO or ISO taking action.[604] ATC calls for a minimum amount of time afforded to stakeholders to review and provide suggestions and feedback on final versions of RTO or ISO filings before they are submitted to the Commission. California Munis suggests that unless there is a physical threat to system reliability or an exigent market condition, no stakeholder meeting should be held without two weeks, and preferably four weeks, minimum notice. It also argues that major market design and policy meetings should not be held the same day, and preferably not on back-to-back days. It further suggests that policy white papers should be available no less than two weeks before the relevant stakeholder meeting.

497. Other commenters want feedback from the RTO or ISO on how their views were taken into account in the decision-making process. ATC calls for establishment of a formal ''feedback loop'' that would provide greater transparency in how stakeholder views are received, reviewed, and considered in an RTO's or ISO's decision-making process. TANC argues that the Commission should require RTOs and ISOs to explain how they considered comments during their decision-making processes.[605] TANC also asks the Commission to require the RTO or ISO to answer specific questions that would describe the stakeholder process employed for developing tariff revisions, and how customer and other stakeholder concerns were rectified.

498. Other commenters call for periodic reviews of the effectiveness of stakeholder processes. LPPC suggests having a periodic survey of customer satisfaction. ATC recommends that RTOs and ISOs be required to submit annual reports to the Commission detailing their adherence to the proposed responsiveness criteria. These reports would provide the Commission with an ongoing mechanism for assessing whether an RTO or ISO is following its approved practices for adhering to the Commission's responsiveness criteria, whether those practices maintain their effectiveness in meeting stakeholders' needs, and whether these practices should be changed.[606] California Munis believes that RTOs and ISOs should be required to make a regular showing to the Commission reviewing their stakeholder processes. NSTAR also encourages the Commission to require RTOs and ISOs to undergo a periodic, independent review of its stakeholder processes including sector membership qualifications, voting weights, and other measures. It contends that the Commission should oversee the review rather than leave it to the stakeholders. This review and recommendation

[597] SMUD at 9.

[598] Maine PUC at 8.

[599] NRECA at 59.

[600] Ameren at 15–16, 37–40.

[601] Old Dominion at 5.

[602] FirstEnergy at 17.

[603] LPPC at 19.

[604] TANC at 13.

[605] *Id.* at 20.

[606] ATC at 10.

should then be used to make constructive changes to the stakeholder processes to ensure that all parties are properly represented.[607]

499. Other commenters want RTOs and ISOs to adopt one another's best practices. For example, NRECA states that the Commission should add a criterion for RTOs and ISOs to follow best practices. NRECA describes the PJM liaison committee meeting process, which allows for direct board access by requiring board member attendance at such meetings, and criteria for vote reporting. NRECA further states that requiring board member participation in substantive committee meetings would provide opportunity for improved communications between stakeholders and the board.[608]

500. Other commenters have further suggestions for improving responsiveness to the needs of customers and other stakeholders. Joint Commenters urge the Commission to adopt three additional requirements for RTOs and ISOs to include in their compliance filings: (1) Improved dissemination of information, (2) well-designed independent operational audits of RTOs and ISOs with stakeholder input, and (3) clarification of the need to adhere to manuals and market rules except under clearly predefined circumstances.[609] LPPC suggests requiring the annual publication of a strategic plan.

4. Commission Determination

501. Based on the various aspects of the proposed responsiveness criteria that the comments address, we discuss three topics in order: Whether to establish an obligation for responsiveness and whether the four responsiveness criteria are appropriate; whether the criteria need greater specificity; and whether additional criteria should be required.

a. Responsiveness Obligation and Appropriateness of the Four Responsiveness Criteria

502. The Commission adopts its proposal from the NOPR and establishes by rule an obligation for each RTO and ISO to make reforms, as necessary, to increase its responsiveness to the needs of customers and other stakeholders. As further detailed below, each RTO and ISO must explain in a filing to the Commission how it is fulfilling, or will fulfill, this obligation. The Commission will assess each RTO's or ISO's filing using the responsiveness criteria discussed below.

503. Although some commenters argue that this requirement is not needed or that RTOs and ISOs are already sufficiently responsive, we find this requirement necessary. For those RTOs and ISOs that may already be satisfying customer needs adequately, this formal requirement will help to focus the attention of RTO and ISO boards and senior management on improvements in this area of great concern to their customers and other stakeholders. As RTOs and ISOs developed, the Commission emphasized that their decision-making processes must be independent of control of any market participant or class of participants. RTO and ISO independence remains fundamental, and we will preserve it; however, we find that RTOs and ISOs must provide an avenue for customers and other stakeholders to present their views on RTO and ISO decision-making, and to have those views considered. Establishing practices and procedures that would allow RTO and ISO boards to be responsive to the concerns of customers and other stakeholders is important to providing these entities with confidence in RTOs' and ISOs' independent governance processes.

504. We will adopt the four responsiveness criteria as proposed in the NOPR. Based on the comments received, we conclude that each of the four criteria has a role in helping us to assess each separate dimension of responsiveness. We also require each RTO and ISO to submit a compliance filing demonstrating how it is responsive to customers and other stakeholders, and we will assess each demonstration based on the four criteria adopted herein.

505. In adopting the four criteria, we have carefully sought to balance customers' and other stakeholders' need for effective access to the boards of RTOs and ISOs, with the need for the independent management of each RTO and ISO. Upon consideration of the comments, the Commission finds that the four criteria are appropriate, balanced, and suitably tailored to improve the responsiveness of RTOs and ISOs to customers and stakeholders.

506. The first criterion, inclusiveness, is intended to ensure that existing or newly-developed practices and procedures, are adequate to bring the views of all customers or other stakeholders before the board. Meeting this criterion will demonstrate that the RTO or ISO actively provides for presenting customer and other stakeholder issues, concerns, or proposals to its boards.

507. The second criterion, fairness in balancing diverse interests, requires that each RTO and ISO ensures that its practices and procedures for decision making consider and balance the interests of their customers and stakeholders, and ensures that no single stakeholder group can dominate. This is necessary to ensure that the RTO or ISO may make well-informed decisions that reflect the full range of competing interests that may be affected.

508. The third criterion, representation of minority interests to the RTO and ISO boards, is also critical to ensure that customers and other stakeholders have confidence in the decisions that come out of RTO and ISO processes. This criterion will ensure that the minority views of customers and stakeholders are forwarded, at the same time as the majority views, to the boards during the deliberation process. The Commission has often been notified that RTO and ISO decisions have been made based only on the single view of the majority vote. While the Commission will not intrude on the governance and decision-making process of RTO and ISO boards and management, it will require that those processes provide for appropriate consideration of minority interests.

509. Finally, through the fourth criterion, ongoing responsiveness, the Commission will require that RTOs and ISOs continue over time to consider customer and other stakeholder needs as the architecture or market environment of the RTO or ISO changes. This criterion is necessary to ensure that responsiveness continues into the future. As with the overall operations of each RTO and ISO, responsiveness to customers and other stakeholders should continually be evaluated for improvement.

510. In response to comments, we clarify that compliance with each criterion must not diminish or limit the requirements for compliance with the remaining criteria. For example, in response to Ameren, we note that the third criterion does not mandate that minority interests overrule majority decisions, rather it requires that the board be made aware of the minority position where necessary. Taken together, the criteria require that RTO and ISO boards be fully aware of the positions of customers and other stakeholders to ensure that issues are fully and fairly vetted.

[607] NSTAR at 11.

[608] NRECA at 60.

[609] Joint Commenters at 3.

b. Specificity of the Responsiveness Criteria

511. While some commenters state that the four responsiveness criteria should be more specific,[610] others support the criteria as proposed, and we conclude that the Commission struck the appropriate balance in the NOPR. The Commission's approach in addressing the responsiveness of RTO and ISO boards is to create a regulatory obligation for RTOs and ISOs to provide greater access in order to better serve the needs of customers and other stakeholders, and to leave the detailed implementation of this obligation for the RTOs and ISOs to work out with their own customers and other stakeholders.

512. As was discussed in the NOPR, and the ANOPR prior to that, during the evolution of RTOs and ISOs, the Commission has allowed each RTO and ISO to develop the necessary operational practices that best suit the needs of its customers and other stakeholders. Differing market designs, governance structures, and existing stakeholder processes should be balanced with the need for independent decision making to provide the greatest benefits to customers and other stakeholders. To create a more expansive set of one-size-fits-all rules would undo that long-held determination.

513. As a result, we do not agree with those commenters who contend that the criteria should be made more specific or set out in more detail. To the contrary, the requirements in this Final Rule will achieve the Commission's goal: RTOs and ISOs will be obligated to demonstrate that they are responsive to the needs of customers and other stakeholders through a direct collaboration among the RTOs and ISOs and their constituencies. Therefore, to specify how an RTO or ISO would be expected to demonstrate compliance with the criteria, as requested by some commenters, would not be consistent with our stated objective in this section of the Final Rule. Upon each RTO's or ISO's submittal of its compliance filing, parties will be free to raise responsiveness issues specific to each RTO or ISO that they believe have not been resolved satisfactorily. With regard to Constellation's request, we clarify that we define ''customer'' as is defined in the RTO's or ISO's tariff.

514. Each RTO or ISO should consider in a collaborative process prior to the submittal of compliance filings the issues or methods that customers and other stakeholders want to raise that they believe will be helpful in satisfying the responsiveness criteria. As suggested in comments filed on the NOPR, such issues and/or methods may include, but need not be limited to, changes of stakeholder processes, board selection methodologies, and monitoring and reporting on the effectiveness of the RTO or ISO in meeting the responsiveness criteria.

c. Additional Criteria

515. We do not agree that additional criteria for responsiveness are necessary at this time. Many of the criteria commenters propose would require specific mandates from the Commission on items that could be resolved by RTOs and ISOs through their own stakeholder procedures. For example, establishing cost-containment requirements or requiring the application of cost/benefit analyses for each RTO or ISO decision in and of themselves are not measures of responsiveness, but rather are practices and procedures that are best developed through the collaborative efforts of each RTO or ISO and their respective customers and other stakeholders. Our objective in requiring RTOs and ISOs to demonstrate their responsiveness to customers and other stakeholders is to ensure that the RTOs and ISOs, in collaboration with their customers and other stakeholders, work toward developing regional solutions suited to the region's needs.

5. Board Advisory Committee and Hybrid Board

516. In the NOPR, the Commission emphasized that various approaches may satisfy the responsiveness criteria and encouraged each RTO or ISO to develop an approach that best suits its own governance structure and stakeholder needs. The Commission asked for comments on two proposed approaches for achieving board responsiveness—a board advisory committee composed of stakeholders and a hybrid board that includes both independent and stakeholder members. The Commission indicated that a board advisory committee would be a particularly strong approach to improving RTO and ISO responsiveness.[611]

a. Comments

517. Commenters generally express support for the board advisory committee as a method of ensuring board responsiveness.[612] They argue that the advisory committee is the better method of balancing the interests of stakeholders without sacrificing the independence of RTO or ISO boards. Others argue, however, that advisory boards do not always allow for meaningful input from stakeholders because they do not have decisional authority.

518. National Grid urges the Commission to resist the inclination to micromanage RTO and ISO governance structure. It states that stakeholders who voluntarily participate in an RTO or ISO should be able to develop their own governance.[613] National Grid states that the governance structures already in place among RTOs and ISOs are products of stakeholder agreements and the Commission should not overturn these compromises.[614]

519. Several RTOs and ISOs note their support for the advisory board concept by pointing to their own existing advisory boards. For example, the Midwest ISO's Advisory Committee consists of 23 representatives from nine stakeholder groups. The Advisory Committee is required to consider separately any measure that is the product of a close vote in committee.[615] PJM states that it successfully worked with its stakeholders to develop and implement a Liaison Committee in 2007. PJM describes the Liaison Committee structure as an attempt to respect the Board's independence in decision making while ensuring accountability and clear communication with the membership.[616]

520. Commenters provide several suggestions to the Commission on how best to structure an advisory board. NARUC suggests that the Commission require that these advisory committees have open positions for state commissions and state consumer advocates.[617] PJM Power Providers recommends that the Commission encourage RTOs or ISOs that select an advisory board approach to recognize diversity as an essential attribute for compliance with the Commission's criteria.

521. PJM Power Providers also suggests that representation on the advisory board should be subject to term limits to ensure diversity over time.[618] PJM Power Providers urges that the Commission encourage representation on the advisory board to be limited to

[610] *See, e.g.*, APPA; ATC; California Munis; NRECA; and SMUD.

[611] NOPR, FERC Stats. & Regs. ¶ 32,628 at P 277.

[612] *See, e.g.*, DRAM at 27; Duke Energy at 2–3; Exelon at 16–17; FirstEnergy at 17; ITC at 12–13; Midwest ISO at 38; NARUC at 19; Old Dominion at 5; OMS at 17–18; Pennsylvania PUC at 20; PJM Power Providers at 12 (board liaison committee); and Steel Producers at 14.

[613] National Grid at 9.

[614] *Id.* at 10.

[615] Midwest ISO at 38.

[616] PJM at 8.

[617] NARUC at 19.

[618] PJM Power Providers at 11.

a defined period with rotating membership. PJM Power Providers recommends that no entity or its affiliates be permitted to have more than one representative on the board advisory committee simultaneously. The Midwest ISO TOs suggest that the advisory committee structure be changed so that transmission owners have a percentage of votes commensurate with the costs they would bear on major expenditures. DRAM agrees with the use of a representative board advisory committee and supports equal representation for demand resources.[619] IID recommends the establishment of an advisory committee to the CAISO Board comprising voluntary representatives from neighboring balancing authority areas bordering or internal to the CAISO.[620]

522. ATC suggests that the Commission should require stakeholder sector representatives to explain the degree to which a vote they cast was supported by their sector's members, and why any minority within a sector disagreed with the majority position. ATC also recommends that RTOs and ISOs and their stakeholders should be allowed to propose exactly how sectors' minority views on main stakeholder committee votes should be conveyed to RTO and ISO boards.[621]

523. Others comment on board selection and composition. The Pennsylvania Commission suggests that the Commission may wish to increase board responsiveness to stakeholders through modifications to the board nominating and selection process. It says that one approach might be to require that all board nominees be selected from an outside consultant's list by a nominating committee that is largely or entirely composed of stakeholder representatives, and/or representatives of the states that the RTO or ISO serves. The Pennsylvania Commission further offers that the Commission should consider prohibiting RTO or ISO management from being part of, or participating in the deliberations of, the board member nominating committee; this will avoid obligating board members to management for their nomination or retention.[622]

524. NSTAR states that while there are requirements for business and technical expertise to serve on the ISO New England board, there is no requirement that any of the members have any experience serving the customers who ultimately pay for the entire market. As a result, NSTAR requests that the Commission consider providing guidance on the composition of boards to include more consumer representatives.[623] The Ohio Commission recommends that the Commission require each RTO and ISO to include on its board at least one individual with extensive state regulatory experience.[624] Moreover, it states that the Commission should compel the RTO's or ISO's board to work with the relevant regional state advisory committee.

525. Regarding hybrid boards, commenters are split on whether a hybrid board represents a valid approach to ensuring board responsiveness. Some commenters argue that a hybrid board is a good alternative to a board advisory committee, and would provide a good way for stakeholders to have input on RTO and ISO decision making. Many more commenters, however, argue that the Commission should not allow hybrid boards. They point to the potential to endanger the independence of the RTO or ISO board and to create conflict of interest for stakeholder board members.

526. TAPS supports the hybrid board approach and says that, with adequate protections, appropriately structured hybrid boards are a better means of achieving a responsive, accountable RTO or ISO than another board advisory committee of stakeholders.[625] TAPS also notes that, by making stakeholders vested partners in board decision making, hybrid boards can change the dynamic of the RTO or ISO, which, it claims, often pits stakeholders against the RTO or ISO. Industrial Consumers also support the hybrid board approach, and suggest that stakeholder members be split equally between representatives of supplier and consumer interests.[626]

527. Other commenters object to the idea of hybrid boards. Industrial Coalitions state that hybrid boards would be unlikely to provide adequate representation for end-use customers, and would further diminish customers' already limited voice in RTO and ISO governance. Industrial Coalitions argue that the proposed criteria for hybrid boards are not sufficient to prevent conflicts of interest on the part of board members.[627] Also, NARUC argues that a hybrid board conflicts with the goal of RTO and ISO independence, and would be unwieldy and ineffective.[628]

528. Duke Energy argues that hybrid boards could create the appearance of, and provide the opportunity for, undue preference in favor of stakeholder board members.[629] ITC argues that mandating or allowing hybrid boards would be a mistake, as this would sacrifice RTO and ISO independence. ITC states that as long as the Commission allows hybrid boards, there will be tremendous pressure on RTOs and ISOs to form a hybrid board, or else be seen as being ''unresponsive'' by stakeholder groups. ITC argues that hybrid boards would violate the principles outlined in Order No. 890, and would allow stakeholders with no interest in new development to block transmission projects. ITC also states that hybrid boards will make it more difficult to develop appropriate transmission pricing systems; for example, stakeholder board members may seek to serve their own interests through allocation of new project costs to others.

529. The Pennsylvania PUC also notes concern regarding stakeholder board members when the board may be required to review competitively sensitive information in making decisions. It states that it is unclear how, or whether, non-independent members would be prevented from reviewing such material.[630]

530. FirstEnergy opposes giving particular stakeholder constituencies preferential rights or privileges under the name of responsiveness, and states that attempts by state commissions to elevate their stakeholder status to advice and approval over RTO or ISO initiatives represent a serious threat to RTO and ISO independence.[631]

531. OMS argues that allowing market participants to hold seats on an RTO or ISO board would jeopardize independence. OMS explains that stakeholder board members can be expected to act in the interests of the companies with which they are affiliated.[632] OMS is also concerned that the members of a hybrid board would create directors unable to fully and fairly exercise their business judgment

[619] DRAM at 27.

[620] IID at 8–9.

[621] ATC at 9. IID also suggests that the Commission's oversight would be aided by requiring RTOs and ISOs to report both majority and minority stakeholder positions to the Commission when they file proposed changes to their rates and tariffs.

[622] Pennsylvania PUC at 19.

[623] NSTAR at 10.

[624] Ohio PUC at 38.

[625] TAPS at 64.

[626] Industrial Consumers at 24.

[627] Industrial Coalitions at 24–32.

[628] NARUC at 18–19.

[629] Duke Energy at 2–3.

[630] Pennsylvania PUC at 18.

[631] FirstEnergy at 17.

[632] OMS at 15.

consistent with general corporate governance law.[633]

532. PJM concurs that hybrid boards are a poor solution given the legal and practical pitfalls associated with these structures.[634] PJM concludes that the NOPR does not demonstrate how the inherent conflicts in fiduciary duties (as well as issues of access to confidential data) would be resolved through a hybrid board structure.[635]

533. The California PUC is sympathetic to the Commission's objectives to improve customer access to RTO and ISO boards of directors and believes that the Commission's proposal of flexibility on this issue is appropriate. However, it states that the requirement that RTOs and ISOs establish a board advisory committee is preferred over the hybrid board approach and the CAISO already has such a mechanism in place and could easily demonstrate to the Commission that it already satisfies the objectives of the NOPR on this issue.[636] The California PUC also states that it is questionable whether the Commission has the legal authority to take the type of actions to reform RTO and ISO boards of directors that are being considered in the NOPR and urges the Commission to proceed only by means of an RTO- or ISO-specific adjudicative process under section 206 of the Federal Power Act. It states that the creation of a hybrid board of directors would violate Order Nos. 888 and 2000, and that the Commission lacks legal authority to impose any reform pertaining to the makeup of the board of directors of a state-created ISO.[637]

b. Commission Determination

534. The Commission will not require RTOs or ISOs to adopt a specific form of board structure—whether board advisory committee, hybrid board, or other—in this rule or when evaluating their compliance filings to determine whether their existing or proposed structures and procedures are appropriately responsive to customers and other stakeholders. The Commission agrees with commenters that a one-size-fits-all approach is not appropriate, given the different needs of each region. As the Commission noted in the NOPR, it views the board advisory committee as a particularly strong mechanism for enhancing responsiveness, and expects each RTO and ISO to work with its stakeholders to develop the mechanism that best suits its needs.

535. The Commission will not require, as proposed by the Ohio Commission, that at least one member of RTO or ISO boards have state regulatory experience. Similarly, the Commission will not require, as proposed by NARUC, that board advisory committees have open positions for state commissions and state consumer advocates. However, these suggestions may be considered by RTOs and ISOs during their own deliberations on compliance with this Final Rule.

536. In response to the comments of California PUC, the Commission notes that the approach adopted in this Final Rule to require each RTO or ISO to submit a compliance filing demonstrating that it has in place or will adopt practices and procedures to ensure that its board of directors is responsive to customers and other stakeholders is within its jurisdictional authority.[638] The Commission is not mandating a specific approach such as a hybrid board of directors in this rulemaking, but is instead establishing a responsiveness objective that each RTO or ISO may meet in its own way.

537. Several commenters argue that the Commission should not allow hybrid boards for legal or practical reasons, including concerns over the independence of RTO and ISO boards. The Commission denied similar requests to disallow hybrid boards in Order No. 2000, noting that RTOs take many different forms to reflect the various needs of each region.[639] The Commission found that a case-by-case review of each RTO board structure was best, with the general guidance that any board including market participants should ensure that no one class would be allowed to veto a decision reached by the rest of the board and that no two classes could force through a decision that is opposed by the rest of the board.[640] We choose to follow our decision on hybrid boards in Order No. 2000 here. As the Commission has found in other circumstances, a hybrid governance structure may be constructed in a way that allows for the expertise of various groups to inform the decision-making process, while still remaining independent such that no individual market participant is given undue influence over the decisions of the board.[641] Our ruling here is not meant to imply that all hybrid board structures are acceptable. RTOs or ISOs wishing to adopt a hybrid board will have to show in their compliance filings that their proposals are consistent with the principles of Order No. 2000 and other relevant precedent. Commenters are free to raise any specific objections to a hybrid board proposal in response to the RTO's or ISO's compliance filing, and the Commission will be able to determine the validity of those objections against a concrete proposal from the RTO or ISO, if any such proposal is made.

6. Supermajority Requirement

538. In the NOPR, the Commission requested comment on whether RTOs and ISOs should be encouraged (or required) to base their process for selecting non-independent members of a board advisory committee, or the board itself, on a supermajority vote of eligible stakeholders.

a. Comments

539. The few commenters that address the issue are split on whether the Commission should require members of advisory boards or hybrid boards to be chosen by a supermajority of stakeholders. Some commenters are skeptical of using a supermajority. Others, such as Steel Producers, believe that it could be beneficial for ensuring that minority perspectives are heard, as those elected to the board by a supermajority would be more likely to be responsive to viewpoints beyond those of their own company or stakeholder segment. Steel Producers argue that a supermajority voting requirement would provide ''minority'' stakeholders a meaningful voice and prevent one group of stakeholders from selecting a disproportionate number of board members.[642]

540. A few commenters suggest that supermajority requirements may be more useful for choosing representatives for specific market sectors; members of each market sector would be allowed to choose their own representatives by a supermajority rather than having voting among the RTO or ISO as a whole.[643] Other commenters argue that the Commission should leave the decision on whether to require a supermajority to regional preference.

541. On the other hand, Comverge is concerned that the use of a supermajority vote to choose board

[633] *Id.* at 15–16.

[634] PJM at 9.

[635] *Id.* at 10.

[636] *Id.* at 56.

[637] California PUC at 54.

[638] *See* Order No. 2000, FERC Stats & Regs ¶ 31,089 at 31,039.

[639] *Id.* at 31,073–74.

[640] *Id.*

[641] *See Western Systems Coordinating Council,* 96 FERC ¶ 61,348, at 62,296 (2001) (approving a hybrid board for WECC). While the WECC is not an RTO, the Commission applied a similar standard to the formation of the WECC board as it applied to RTOs in Order No. 2000.)

[642] Steel Producers at 14.

[643] *See* APPA; California Munis.

representatives would make it difficult to reconcile minority positions with demand response interests and suggests that the Commission consider support for separate board advisory committees that are intended primarily to represent demand response and demand-side resources.[644]

542. Xcel believes that the Commission should narrowly define ''stakeholder'' to ensure that a stakeholder is not simply any person in the room. For example, in some organized markets, *e.g.*, the Midwest ISO, the advisory structure permits each stakeholder sector to ballot only within its own sector, which reduces the risk of one sector dominating the overall ballots.[645]

543. SMUD indicates that its comments on the ANOPR urged adoption of requirements that: (1) The RTO or ISO give stakeholders a formal voting process to express their views, and (2) the RTO or ISO explain when it ignores supermajority sentiments.[646] SMUD claims that the NOPR's more vague requirements are insufficient; thus specific directives should be set forth in any final action.

544. PJM suggests that a supermajority requirement is not a necessary or sufficient one, and argues that the Commission should instead encourage RTOs or ISOs that choose to establish an advisory board to recognize diversity as an essential attribute for compliance with the Commission's guidelines.

545. Finally, ITC notes that a supermajority requirement, as suggested in the NOPR, may or may not be beneficial for hybrid boards and would further politicize the board selection process. Additionally, ITC argues that because advisory committees do not have decision making authority, a supermajority would not be necessary or appropriate for choosing advisory committee members.[647]

b. Commission Determination

546. The Commission will leave it to each RTO or ISO, in consultation with its customers and other stakeholders, whether to select by supermajority vote members of any board advisory committee or any non-independent board member. When determining whether to implement a supermajority requirement, RTOs and ISOs should consider the goals of achieving a voice for minority interests while also having a workable process.

7. Posting Mission Statement or Organizational Charter on Web Site

547. In the NOPR, the Commission proposed to require that each RTO and ISO post on its Web site a mission statement or charter for its organization. The Commission encouraged each RTO and ISO to set forth in either the mission statement or the organizational charter its purpose, guiding principles, and commitment to responsiveness to customers and other stakeholders, and ultimately to the consumers who benefit from and pay for electricity services.

a. Comments

548. Most commenters who discuss the topic indicate that they support the Commission's proposed requirement for RTOs or ISOs to post a mission statement or organizational charter on their Web sites. Both CAISO and NYISO report that they already post mission statements on their Web site.[648]

549. Other commenters provide additional thoughts on RTO and ISO mission statements on a more general level. Constellation also supports having a requirement that each RTO and ISO publish a mission statement setting forth the organization's purpose, guiding principles, and commitment to responsiveness to customers and other stakeholders. It advocates that the mission statement should reflect and include the minimum characteristics and functions that the Commission has required for each RTO and ISO in Order No. 2000.[649]

550. North Carolina Electric Membership requests that the Commission require RTOs and ISOs revisit their mission statements to ensure that the statements are consistent with the Order No. 2000 core objectives. It asserts that paramount among the core objectives should be the twin goals of facilitating open access to the transmission grid and providing reliable electric service at an affordable cost to consumers. North Carolina Electric Membership adds that the mission statements should also set forth defined roles for the RTO and ISO boards and management, as well as defined roles for stakeholders in accomplishing the objectives set forth in those statements. Old Dominion also sees value in defining within the mission statement the roles of the board, RTO and ISO management and stakeholders to provide the clarity necessary to be sure that the organization is aligned with the RTO's and ISO's mission.[650]

551. NRECA and Old Dominion argue that RTOs and ISOs should be required to include their mission statements in their tariffs and that the mission statements should include a focus on lowering costs for transmission and wholesale power customers. NRECA notes that absent from the mission statements currently posted on many RTO and ISO Web sites is a focus on ensuring that overall costs to consumers are consistent with the objective of ensuring just and reasonable rates for consumers.[651]

552. Steel Producers note that an RTO's or ISO's mission statement and/or charter should not be utilized by the RTO and ISO, its stakeholders, or market participants to limit the range or scope of potential issues that the RTO or ISO and/or its respective stakeholder group(s) may need to address. They conclude that mission statements and charters should provide guidance, but should not foreclose discussion and action on pertinent matters of interest.[652]

553. TAPS asserts that ''the Final Rule should require each RTO to file a mission statement that makes it accountable to consumers for meeting the purposes of the Federal Power Act.'' [653] TAPS argues that the Federal Power Act's purpose is to ensure that electricity consumers pay the lowest prices possible for reliable service. TAPS concludes that by establishing consumer value as a core goal for RTOs and ISOs, the Commission would align the goals of these regional organizations with the objectives of state regulators, federal policy makers, and consumers.

554. SMUD states that the NOPR failed to further discuss the issue of whether RTOs and ISOs should be required to publish a strategic plan, as was raised in the ANOPR. SMUD avers, however, that such a requirement is implicit in the NOPR discussion where RTOs and ISOs would be required to show that they have satisfied the criteria, including responsiveness to stakeholders. SMUD requests that the Commission clarify that its intent was to require RTOs and ISOs to publish strategic plans.

555. FirstEnergy opposes an RTO or ISO mission statement that deviates from the contractual and tariff obligations under which the RTO or ISO currently operates, and states that any effort to adopt such a statement would be problematic, and a source of

[644] Comverge at 24.

[645] Xcel at 14.

[646] *Id.* at 12.

[647] ITC at 12–13.

[648] CAISO at 12; NYISO at 18.

[649] Constellation at 19.

[650] Old Dominion at 5.

[651] NRECA at 62.

[652] Steel Producers at 14–15.

[653] TAPS at 60.

additional and unneeded controversy among RTO and ISO stakeholders.[654]

b. Commission Determination

556. The Commission will require each RTO and ISO to post on its Web site a mission statement or organizational charter. The Commission encourages each RTO and ISO to include in its mission statement, among other things, the organization's purpose, guiding principles, and commitment to responsiveness to customers and other stakeholders, and ultimately to the consumers who benefit from and pay for electricity services. The mission statement or organizational charter may include additional information, such as elements from the RTO or ISO governing documents. The Commission does not expect that any explicit statement of the responsiveness objective would conflict with existing elements of the RTO's or ISO's mission.

557. We find that this requirement will improve communication between RTOs and ISOs and their stakeholders and the community at large, as well as provide a statement of goals by which the RTO's and ISO's progress may be judged. If any RTO or ISO believes that there is a conflict between this requirement and the existing mission statement, contracts or tariff, the RTO or ISO may address this conflict in its compliance filing. In response to SMUD, we clarify that publication of a strategic plan is not implicit in the responsiveness obligation.

8. Executive Compensation

558. In the NOPR, the Commission encouraged, but did not propose to require, each RTO and ISO to ensure that its management programs, including, but not limited to, incentive compensation plans for executive managers, give appropriate weight to stakeholder responsiveness.

a. Comments

559. Commenters generally agree that RTOs and ISOs should link compensation plans for executive managers to customer service measures of performance, as indicated by customer satisfaction surveys and complying with the responsiveness criteria.

560. LPPC asks for establishment of objective criteria for performance and executive compensation.[655] Additionally, North Carolina Electric Membership argues that the Final Rule should require RTOs and ISOs to demonstrate that their executive management incentive programs are tied to their mission statements, including a focus on improving customer service, properly managing their markets, being responsive and accountable to stakeholders and consumers, and providing consumers with reliable service at an affordable cost.[656]

b. Commission Determination

561. The Commission continues to encourage, but not require, each RTO and ISO to ensure that its management programs, including executive compensation, give appropriate weight to responsiveness to customers and other stakeholders. If the RTO or ISO board is well-informed about the needs of customers and various stakeholders, it will set criteria for performance, appropriate goals and targets for the organization and its management and institute measures for achieving those targets. By focusing our requirements on having a well-informed board, we decline to intrude further into board prerogatives regarding management compensation.

9. Compliance Filing Requirement

562. In the NOPR, the Commission determined that each RTO or ISO must comply with this proposed requirement by submitting a filing that proposes changes to its board responsiveness practices and procedures to comply with the proposed criteria or that demonstrates its practices and procedures already satisfy the criteria for board responsiveness.[657] This filing would be submitted within six months of the date the Final Rule is published in the **Federal Register**. The Commission also stated that it will assess whether each filing satisfies the proposed requirement and issue additional orders as necessary.

a. Comments

563. Most commenters support a compliance filing requirement. However, some commenters expressed concern that RTOs and ISOs will merely submit documentation asserting that their existing processes already satisfy the responsiveness criteria, without working seriously with stakeholders to ensure that stakeholder input is sought on compliance. The California PUC states that it believes that CAISO already meets the requirements of the NOPR and asks the Commission to refrain from taking any further action regarding the responsiveness of RTOs and ISOs to stakeholders and customers needs.[658]

564. Industrial Coalitions state that the Final Rule should not delegate to the RTO or ISO stakeholder processes the task of working out the details of the Commission's proposals. Industrial Coalitions are concerned that the Commission's approach will delay resolution of these important matters, to the detriment of customers. Accordingly, Industrial Coalitions urge the Commission to provide clear and consistent directives regarding the subject matter and timing of the RTO and ISO compliance filings.[659]

b. Commission Determination

565. The Commission requires each RTO or ISO to make a compliance filing that proposes changes to its responsiveness practices and procedures to comply with the responsiveness requirement or that demonstrates that its practices and procedures already satisfy the requirement for responsiveness. The compliance filing also must propose posting, or report the posting, of the RTO's or ISO's mission statement or organizational charter on its respective Web site. This filing shall be submitted within six months of the date this Final Rule is published in the **Federal Register**.

566. We recognize that many of the existing RTOs and ISOs have a form of committee (whether advisory board or stakeholder committee) that functions within the RTO or ISO governance structure to provide stakeholder feedback. Given the number of comments from interested parties seeking improvement to their interactions with RTO and ISO boards and the effectiveness of these committees, it is important that the compliance filings required herein follow from consultation with customers and other stakeholders regarding satisfaction with existing processes and the appropriateness of improved processes. In the end, however, the filing is the RTO's or ISO's to make; we urge them to seek consensus but realize that complete agreement is not always achievable. This consultation process is worth additional time and effort, and should not cause an excessive delay, given the six-month time allowed for filing.

567. Each RTO or ISO should explain in its compliance filing how it plans to satisfy, or currently satisfies, each responsiveness criterion. Furthermore, each RTO and ISO should include in its

[654] FirstEnergy at 17.

[655] LPPC at 18.

[656] North Carolina Electric Membership at 25–26.

[657] NOPR, FERC Stats. & Regs. ¶ 32,628 at P 276.

[658] California PUC at 56.

[659] Industrial Coalitions at 4.

compliance filing, for each criterion, an explanation of the process (*e.g.*, stakeholder meetings, technical conferences, board discussions) that the RTO and ISO used to develop its compliance filing demonstration and describe major dissenting views. In the event RTOs or ISOs, working with their customers and other stakeholders, complete the responsiveness compliance requirements in less than six months, they may file them ahead of the specified due date. The Commission will assess whether each filing satisfies the proposed requirement and issue additional orders as necessary.

E. Other Comments

1. Comments

568. A few commenters address topics other than the specific proposals in the NOPR. For example, some suggest we require, or promote as part of the Final Rule, the review of RTO and ISO seams and rate levels, performance benchmarking, moratoriums on new RTO or ISO products and services, cost-benefit analyses,[660] time-sensitive rates for transmission and other non-market services with marginal costs caused by on-peak usage,[661] interconnection requirements,[662] tariff filings, and reviews related to the design and scope of independent operational audits of RTOs and ISOs.[663] CAISO and the Cities filed reply comments in opposition to implementing time-sensitive rates.[664]

569. First Energy is opposed to RTOs and ISOs recovering from market participants penalties for NERC reliability violations caused by RTOs.[665]

570. Another commenter asked that the Commission avoid, to the extent possible, requiring compliance filings at times when RTOs and ISOs are focused on start up of new markets.[666]

571. In its comments, Sorgo expresses concern that the April 2007 Report to Congress on Competition in Wholesale and Retail Markets failed to address anticompetitive policies that may favor old power plants.[667]

572. Allied Public Interest Groups states that the Commission should direct RTOs and ISOs to give comparable consideration to demand response resources in regional planning, and that regional planning should include scenario analyses evaluating the amounts of potentially available demand response resources.[668]

2. Commission Determination

573. The Commission appreciates the efforts involved in developing these comments and proposals submitted in this rulemaking. We note that these topics have already been addressed by the Commission in Order No. 890[669] and Order No. 693.[670] Accordingly, the Commission declines to expand the scope of this proceeding to encompass topics not presented in the NOPR. RTOs and ISOs and their stakeholders may address these topics, if they so choose, through their own processes for evolving RTO and ISO services and markets.

IV. Applicability of the Final Rule and Compliance Procedures

A. NOPR Proposal

574. In the NOPR, the Commission proposed to apply the Final Rule to all RTOs and ISOs, and to require them to demonstrate compliance with the requirements in each of the four sections of the Final Rule.[671] The Commission proposed to require each RTO and ISO to file a report to the Commission within six months of the Final Rule's effective date, or six months following its certification as an RTO or commencement of operations as an ISO. The Commission proposed that the compliance filing should describe whether the RTO or ISO already complies with the requirements of the Final Rule, or describe the entity's plans to attain compliance, including a timeline with intermediate deadlines and appropriate proposed tariff and market rule revisions. The Commission noted that it would assess whether each filing satisfies the proposed requirements and issue further orders for each RTO and ISO, as necessary.

B. Comments

575. The Commission received few comments on the applicability and compliance proposals. Ameren notes that the six-month period for compliance may coincide with the implementation period for the Midwest ISO's Ancillary Services Market. Accordingly, Ameren argues that the Commission should avoid, to the extent possible, requiring compliance filings at times when RTOs and ISOs are focused on the start of new markets.[672]

576. CAISO requests clarification from the Commission as to whether the six-month compliance deadline is intended to apply to those market enhancements that CAISO already has planned under its Market Redesign and Technology Upgrade. CAISO notes that many of these upgrades, including allowing demand response to supply ancillary services and implementing enhanced shortage pricing, are on a separate timeline approved by the Commission.[673]

577. NYISO states that it supports the compliance deadlines in the NOPR, and calls on the Commission to reject any proposal calling for shorter compliance periods. NYISO notes that given the number of changes to RTO or ISO market software, billing practices and organizational functions that would be required by the Final Rule, along with the time required to consult with stakeholders, the proposed deadlines are the minimum necessary time for preparation of compliance filings.[674]

C. Commission Determination

578. As we proposed in the NOPR, we will require RTOs and ISOs to make a compliance filing within six months of the date that this Final Rule is published in the **Federal Register**. RTOs and ISOs should work with stakeholders and interested parties, where applicable, to comply with this rule and to develop their compliance filings.

579. The six-month period appropriately recognizes that it is important for RTOs and ISOs to work with stakeholders and other interested parties to develop a compliance filing, and that (as NYISO contends) such processes take time. In response to Ameren and CAISO, we clarify that the compliance requirement is not meant to displace the timelines of any market improvements that RTOs or ISOs are currently undertaking. Each RTO and ISO should include in its compliance filing an update on the status of any relevant market design changes that are

[660] AMPA at 2–6; APPA at 10, 19, 102–03; Indianapolis P&L at 5;Industrial Coalitions at 23–24.

[661] California DWR at 3, 21–36, and 38–39.

[662] American Forest at 2.

[663] Joint Commenters at 6–10.

[664] CAISO and the Cities at 3.

[665] FirstEnergy at 19.

[666] Ameren at 16.

[667] Sorgo at 1. The April 2007 Report to Congress on Competition in Wholesale and Retail Markets was developed by the Electric Energy Market Competition Task Force as directed by Section 1815 of the Energy Policy Act of 2005.

[668] Allied Public Interest Groups at 13–14.

[669] Order No. 890 requires any public utility with an OATT to allow qualified demand response resources to participate in its regional transmission planning process on a comparable basis to generation resources and to allow qualified demand response to provide certain ancillary services. Order No. 890, ¶ FERC Stats. & Regs. ¶ 31,241 at P 479, 494, and 888.

[670] Order No. 693 requires the Electricity Reliability Organization to revise its reliability standards so that all technically feasible resource options, including demand response and generating resources, may be employed in the management of grid operations and emergencies. Order No. 693, FERC Stats. & Regs. ¶ 31,242.

[671] NOPR, 122 FERC ¶ 61,167 at P 283.

[672] Ameren at 16.

[673] CAISO at 2.

[674] NYISO at 22.

in the process of being implemented and address any remaining issues not addressed by the ongoing changes. It need not change the schedule for implementing these other market design changes as a result of this Final Rule.

580. The compliance filing should explain the action the RTO or ISO has taken, or plans to take, to comply with the requirements in each of the four sections of this Final Rule. It should also describe, where applicable, the process used to develop the compliance filing and describe any major dissenting views. The Commission will evaluate each compliance filing to determine whether it satisfies the requirements in this rule, and issue additional orders as necessary.

581. As described above, RTOs and ISOs, in cooperation with their customers and stakeholders, also are required to perform an assessment, through pilot projects or other mechanisms, of the technical feasibility and value to the market of smaller demand response resources providing ancillary services, including whether (and how) smaller resources can reliably and economically provide operating reserves and report their findings to the Commission. This assessment is due to the Commission within one year of the date that this Final Rule is published in the **Federal Register**.

582. Finally, as described above, each RTO's and ISO's market monitoring unit is required to comment on the adequacy of market mitigation measures in its respective RTO's or ISO's shortage pricing proposal. This requirement will aid the Commission in evaluating the proposals once they are filed.

583. In response to commenters who argue that the six-month requirement for submission of a compliance filing is either too long or too short, we find that the six-month period is an adequate amount of time for an RTO or ISO to work with stakeholders and other interested parties to develop a compliance filing. We note that RTOs and ISOs may make their compliance filing at any time prior to the end of the six-month period.

V. Information Collection Statement

584. The Office of Management and Budget (OMB) regulations require approval of certain information collection requirements imposed by agency rules.[675] Upon approval of a collection(s) of information, OMB will assign an OMB control number and an expiration date. Respondents subject to the filing requirements of this rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number. This Final Rule amends the Commission's regulations to improve the operation of organized wholesale electric power markets. The objective of this Final Rule is to improve market design and competition in organized markets. Through this rule the Commission hopes to provide remedies by: (1) Ensuring that new criteria are established so that RTOs and ISOs are responsive to their customers and stakeholders; (2) improving market monitoring within RTOs and ISOs by requiring them to provide their Market Monitoring Units with access to market data and sufficient resources to perform their duties; (3) providing transparency in the marketplace by requiring RTOs and ISOs to dedicate portions of their Web sites so market participants can avail themselves of information concerning offers to buy or sell power on a long-term basis; and (4) requiring RTOs and ISOs to institute certain reforms in the demand response programs to remove several disincentives and barriers to demand response so as to provide for more efficient operation of markets and encourage new technologies. Filings by RTOs and ISOs would be made under Part 35 of the Commission's regulations. The information provided for under Part 35 is identified as FERC–516.

585. The Commission is submitting these reporting requirements to OMB for its review and approval under section 3507(d) of the Paperwork Reduction Act.[676] The Commission solicited comments on the Commission's need for this information, whether the information will have practical utility, the accuracy of provided burden estimates, ways to enhance the quality, utility, and clarity of the information to be collected, and any suggested methods for minimizing the respondent's burden, including the use of automated information techniques. The Commission did not receive comments specifically addressing the burden estimates in the NOPR. Therefore we will use the same estimates here as in the NOPR.

Burden Estimate: The Public Reporting burden for the requirements contained in the Final Rule is as follows:

Data collection	Number of respondents	Number of responses	Hours per response	Total annual hours
FERC–516 Task:				
Allow demand response to provide certain ancillary services	6	1	433	2,598
Remove certain deviation charges	5	1	288	1,440
Permit aggregation of Retail Customers	6	1	102.5	615
Allow pricing to ration demand during a shortage	6	1	649	3,894
Long-term contract postings	6	1	30	180
MMUs	6	1	129	774
Require RTO board responsiveness to customers	6	1	180	1,080
Require RTO self-assessment	6	1	650	3,900
Totals				14,481

Total Annual Hours for Collection: (Reporting + recordkeeping, (if appropriate)) = Total hours for performing tasks 1 through 8 as identified above = 14,481 hours.

Information Collection Costs: The average annualized cost[677] is expected to be:

Legal expertise = $473,526 (2,368 hours @$200 an hour)

Technical Expertise = $712,038 (4,747 hours @$150 an hour) (RTO/ISO Senior Staff, Stakeholder participants)

Administrative Support = $108,701 (2,718 hours @$40 an hour)

[675] 5 CFR 1320.11.

[676] 44 U.S.C. 3507(d).

[677] Differences in RTO/ISO staff hourly rates are to differentiate between administrative support staff and senior staff.

IT Support = $236,448 (2,489 hours @ $95 an hour)
Participatory Expenditures = $2,160,000 (96 participants @$1,000 per day on average 4.5 days per activity for five of the eight activities identified above).
Total = $3,690,713.

Title: FERC–516 ''Electric Rate Schedule Filings.''

Action: Proposed Collections.

OMB Control No: 1902–0096.

Respondents: Business or other for profit, and/or not for profit institutions.

Frequency of Responses: An initial filing to comply with the rule, and then on occasion as needed to revise or modify.

Necessity of the Information: This Final Rule furthers the improvement of competitive wholesale electric markets and the provision of transmission services in the RTO and ISO regions. The Commission recognizes that significant differences exist among the regions, industry structures, and sources of electric generation, population demographics and even weather patterns. In fulfilling its responsibilities under sections 205 and 206 of the Federal Power Act, the Commission is required to address, and has the authority to remedy, undue discrimination and anticompetitive effects.

586. Interested persons may obtain information on the reporting requirements by contacting: Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426 [Attention: Michael Miller, Office of the Executive Director, Phone: (202) 502–8415, fax: (202) 273–0873, e-mail: *michael.miller@ferc.gov.* Comments on the requirements of the proposed rule may also be sent to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission, fax (202) 395–7285, e-mail: *oira_submission@omb.eop.gov.*

VI. Environmental Analysis

587. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[678] The Commission concludes that neither an Environmental Assessment nor an Environmental Impact statement is required for this Final Rule under section 380.4(a)(15) of the Commission's regulations, which provides a categorical exemption for approval of actions under sections 205 and 206 of the FPA relating to the filing of schedules containing all rates and charges for the transmission or sale subject to the Commission's jurisdiction, plus the classification, practices, contracts, and regulations that affect rates, charges, classifications, and services.[679]

VII. Regulatory Flexibility Act Certification

588. The Regulatory Flexibility Act of 1980 (RFA)[680] generally requires a description and analysis of rules that will have significant economic impact on a substantial number of small entities. The RFA does not mandate any particular outcome in a rulemaking. It only requires consideration of alternatives that are less burdensome to small entities and an agency explanation of why alternatives were rejected.

589. In drafting a rule an agency is required to: (1) Assess the effect that its regulation will have on small entities; (2) analyze effective alternatives that may minimize a regulation's impact; and (3) make the analyses available for public comment.[681] In its NOPR, the agency must either include an initial regulatory flexibility analysis (initial RFA)[682] or certify that the proposed rule will not have a ''significant impact on a substantial number of small entities.''[683]

590. If in preparing the NOPR an agency determines that the proposal could have a significant impact on a substantial number of small entities, the agency shall ensure that small entities will have an opportunity to participate in the rulemaking procedure.[684]

591. In its Final Rule, the agency must either prepare a Final Regulatory Flexibility Analysis (Final RFA) or make the requisite certification. Based on the comments the agency receives on the NOPR, it can alter its original position as expressed in the NOPR, but it is not required to make any substantive changes to the proposed regulation.

592. The statute provides for judicial review of an agency's final certification or Final RFA.[685] An agency must file a Final RFA demonstrating a ''reasonable, good-faith effort'' to carry out the RFA mandate.[686] However, the RFA is a procedural, not a substantive, mandate. An agency is only required to demonstrate a reasonable, good-faith effort to review the impact the proposed rule would place on small entities, any alternatives that would address the agency's and small entities concerns and their impact, provide small entities the opportunity to comment on the proposals, and review and address comments. An agency is not required to adopt the least burdensome rule. Further, the RFA does not require the RFA to assess the impact of a rule on all small entities that may be affected by a rule, only on those entities that the agency directly regulates and that will be directly impacted by the rule.[687]

A. NOPR Proposal

593. In the NOPR, the Commission stated that most, if not all, of the transmission organizations to which this rule would apply do not fall within the definition of small entities.[688] The Commission identified the characteristics of each of those organizations and all exceeded the standard size definition established in NAICS.[689] It should be noted that due to typographical error in the NOPR, footnote 292 omitted the word ''million'' when identifying the size standard applicable to utilities.

594. One of those requirements proposed in the NOPR was that ''RTO and ISOs must amend their market rules as necessary to permit an ARC to bid demand response on behalf of retail customers directly into the RTO's or ISO's organized markets, unless the laws or regulations of the relevant electric retail regulatory authority do not permit a retail customer to participate.''[690] The Commission reasoned that such action would reduce obstacles for small retail loads to be able to participate in organized markets by

[678] *Regulations Implementing the National Environmental Policy Act,* Order No. 486, FERC Stats. & Regs. ¶ 30,783 (1987).

[679] 18 CFR 380.4(a)(15).

[680] 5 U.S.C. 601–12.

[681] 5 U.S.C. 601–604.

[682] 5 U.S.C. 603(a).

[683] 5 U.S.C. 605(b).

[684] 5 U.S.C. 609(a).

[685] 5 U.S.C. 611.

[686] *United Cellular Corp. v. FCC,* 254 F.3d 78, 88 (DC Cir. 2001); *Alenco Communications, Inc. v. FCC,* 201 F.3d 608, 625 (5th Cir. 2000).

[687] *Mid-Tex Electric Coop., Inc. v. FERC,* 773 F.2d 327 (DC Cir. 1985) (Mid-Tex).

[688] NOPR, FERC Stats. & Regs. ¶32,628 at P 291.

[689] The RFA definition of ''small entity'' refers to the definition provided in the Small Business Act, which defines a ''small business concern'' as a business that is independently owned and operated and that is not dominant in its field of operation. *See* 5 U.S.C. 601(3), citing to Section 3 of the Small Business Act, U.S.C. 632. The Small Business Size Standards component of the North American Industry Classification System defines a small utility as one that, including its affiliates is primarily engaged in the generation, transmission, or distribution of electric energy for sale, and whose total electric output for the preceding fiscal years did not exceed 4 million MWh. 13 CFR 121.202 (Sector 22, Utilities, North American Industry Classification System (NAICS)) (2004).

[690] NOPR, FERC Stats. & Regs. ¶32,628 at P 86.

allowing ARCs to assemble small demand responses that individually are too small to qualify for bidding into an RTO or ISO organized market and having ARCs assume many of the administrative tasks that retail customers may lack the resources or cannot afford. Simultaneously, as the Commission pointed out from comments received in response to its ANOPR, ARCs can reduce the RTO's and ISO's administrative burden of managing individual customers' demand response participation.[691]

595. Thus, in the NOPR, based on comments to the ANOPR, the Commission sought to ameliorate administrative burdens on small entities, specifically small retail customers to be able to participate in organized market and access demand response programs.

1. Comments

596. APPA and TAPS argue that the inclusion of ARCs, while assisting small retail customers, disproportionately shifts the burden to relevant electric retail regulatory authorities. APPA does not support the Commission's proposal that RTOs presume that aggregation is allowed unless the relevant electric retail regulatory authority informs the RTO that it does not permit aggregation.[692] APPA provides data on the number of power systems providing retail service in RTO regions and states that the vast majority of these are small utilities within the meaning of the RFA.[693]

597. TAPS, while recognizing the Commission's efforts, also has concerns about the Commission's proposal. TAPS believes the ''proposal would place undue burdens on many individual nonregulated electric utilities to take affirmative regulatory actions to maintain their authority * * *.''[694] TAPS believes that if relevant electric retail regulatory authorities must assume the responsibility to notify RTOs then this places undue burden on municipal entities to become involved in lengthy legislative processes to make determinations that may have already been made on whether ARCs may aggregate the demand response of the municipals' loads.[695]

598. APPA believes the Commission is giving the RTOs and ISOs authority to trump state and local laws and regulations when it allows RTOs and ISOs to accept bids from an ARC whether or not the laws and regulations of the relevant electric retail regulatory authority explicitly permits it.[696] APPA believes that the retail regulatory authority will be placed in the position of having to make an administrative finding of whether aggregation by ARCs of retail end users is to be permitted. By APPA's count, only a small proportion of the 1,315 public power systems that provide retail electric service in states served by RTOs and ISOs have such laws or regulations. For the majority, this would result in a huge learning curve to become familiar with the process and consequently result in a ''very substantial undertaking.''[697] APPA estimates that approximately 1,307 of the power distribution systems located in states served by RTOs and ISOs are ''small utilities'' as the term is defined in the RFA. To require relevant electric retail regulatory authorities to consider an affirmative pronouncement on this issue is ''cumulatively a very substantial FERC-imposed burden on them.''[698]

599. APPA believes that unless a system's relevant electric retail regulatory authority affirmatively informs an RTO or ISO that it permits such aggregation by third-party ARCs, the RTO or ISO should be required to assume that such aggregation is not permitted. Should the Commission not accept APPA's proposal, as an alternative APPA suggest that for relevant electric retail regulatory authorities governing public power systems located in RTO and ISO regions that exceed the RFA size requirement, they would have to consider the issue of third-party ARCs and aggregation of their retail customers. In the case of public power systems that do not meet the RFA size requirement, then the RTO or ISO would be responsible for making the assumption that aggregation by ARCs is not permitted.[699]

600. TAPS takes a similar position. It believes the NOPR can be interpreted to require municipal systems to take legislative or regulatory action specific to the third-party ARC issue and notify the RTO or ISO. For these municipal systems to respond particularly when they do not allow retail access will impose significant burdens on them. As an indication of the potential impact, TAPS identified the number of municipal systems served by their members including AMP-Ohio with 122 municipal electric systems in both Midwest ISO and PJM; Indiana Municipal Power Agency, which serves 51 municipal electric systems in Midwest ISO; and Wisconsin Public Power Inc. which serves 50 municipal electric systems in Midwest ISO.[700] TAPS reminds the Commission that Congress, through passage of the RFA, requires agencies to assess the impact on entities whose total electric output does not exceed 4 million MWh. TAPS notes that the Commission's certification in the NOPR recognized this responsibility, but failed to account for ''the hundreds of small entities that it proposes to effectively put through this legislative or regulatory process.''[701]

601. TAPS believes the Commission can achieve its objective by rewording its requirement to have relevant electric retail regulatory authorities notify the RTO or ISO when they permit third-party ARCs. Unless there is a notification, the RTO or ISO is to assume that third-party aggregation is not permitted. By shifting the emphasis as to when the notification is to take place, hundreds of municipals would not be burdened by having to go through the legislative process. In addition, only systems with a total electric output exceeding 4 million MWh would have to go through the process. TAPS also proposes an additional alternative, namely that municipals with retail sales of more than 500 million kWh as specified in PURPA would have to go through the process.[702]

2. Commission Determination

602. The Final Rule is applicable to all RTOs and ISOs. The Commission is requiring each RTO and ISO to make certain filings that reflect amendments to their tariffs to demonstrate they have either incorporated, or already have in place, processes that implement the requirements of this Final Rule. None of these entities, as identified in the NOPR, meets the RFA definition of a small entity—in particular, the last criterion of the definition ''and which is not dominant in its field of operation.''[703]

603. In *Mid-Tex*, the court accepted the Commission's conclusion that, since virtually all of the public utilities that it regulates do not fall within the meaning of the term ''small entities'' as defined in the RFA, the Commission did not need to prepare a regulatory flexibility analysis in connection with its proposed rule governing the allocation of costs for construction work

[691] *Id.* P 83.

[692] APPA at 3.

[693] *Id.* at 3.

[694] TAPS at 13

[695] *Id.* at 17.

[696] APPA at 43.

[697] *Id.* at 44.

[698] *Id.* at 45.

[699] *Id.* at 47.

[700] TAPS at 19.

[701] *Id.* at 20.

[702] *Id.*

[703] 5 U.S.C. 601(3) and 601(6) and 15 U.S.C. 632(a)(1) (defining ''small business concern'').

in progress (CWIP).[704] The CWIP rules applied to *all* public utilities. This Final Rule applies only to RTOs and ISOs, which are a subset of ''all public utilities'' for which the regulatory flexibility analysis was not required.

604. In a subsequent court decision, *American Trucking Associations, Inc. v. EPA*,[705] the U.S. Court of Appeals for the District of Columbia applied the decision in *Mid-Tex* to its determination. The Environmental Protection Agency (EPA) established a primary national ambient air quality standard for ozone and particulate matter. The basis of EPA's certification was that the standard regulated small entities indirectly through state implementation plans. The court found that because the states, not EPA, had the direct authority to impose the burden on small entities, EPA's regulation did not have a direct impact on small entities.

605. Here APPA and TAPS contend that hundreds of small municipal systems would have to undertake legislative or regulatory actions in order to respond to the RTO. We disagree with their contention. No relevant electric retail regulatory authority is required to take any action under this rule. For these reasons, the Commission certifies that this Final Rule will not have a significant economic impact on a substantial number of small entities.

VIII. Document Availability

606. In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's Home Page (*http://www.ferc.gov*) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5 p.m. Eastern time) at 888 First Street, NE., Room 2A, Washington, DC 20426.

607. From FERC's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

608. User assistance is available for eLibrary and the Commission's Web site during normal business hours from FERC Online Support at 202–502–6652 (toll free at 1–866–208–3676) or e-mail at *ferconlinesupport@ferc.gov*, or the Public Reference Room at (202) 502–8371, TTY (202) 502–8659. E-mail the Public Reference Room at *public.referenceroom@ferc.gov.*

[704] *Mid-Tex*, 773 F.2d 327 at 342.

[705] *American Trucking Ass'ns v. EPA*, 175 F.3d 1027, 1044 (DC Cir. 1999), *aff'd in part and rev'd in part sub nom., Whitman v. American Trucking Ass'ns*, 531 U.S. 457 (2001).

IX. Effective Date and Congressional Notification

609. These regulations are effective December 29, 2008. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is not a ''major rule'' as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996. The Commission will submit the Final Rule to both houses of Congress and the Government Accountability Office.

By the Commission. Commissioner Kelly concurring in part and dissenting in part with a separate statement attached.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

■ In consideration of the foregoing, the Commission amends part 35, Chapter I, Title 18, of the *Code of Federal Regulations*, as follows:

PART 35—FILING OF RATE SCHEDULES AND TARIFFS

■ 1. The authority citation for part 35 continues to read as follows:

Authority: 16 U.S.C. 791a–825r, 2601–2645; 31 U.S.C. 9701; 42 U.S.C. 7101–7352.

■ In § 35.28 add new paragraphs (b)(4) through (b)(8) and (g) to read as follows:

§ 35.28 Non-discriminatory open access transmission tariff.

* * * * *

(b) *Definitions* * * *

(4) *Demand response* means a reduction in the consumption of electric energy by customers from their expected consumption in response to an increase in the price of electric energy or to incentive payments designed to induce lower consumption of electric energy.

(5) *Demand response resource* means a resource capable of providing demand response.

(6) *An operating reserve shortage* means a period when the amount of available supply falls short of demand plus the operating reserve requirement.

(7) *Market Monitoring Unit* means the person or entity responsible for carrying out the market monitoring functions that the Commission has ordered Commission-approved independent system operators and regional transmission organizations to perform.

(8) *Market Violation* means a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.

* * * * *

(g) *Tariffs and operations of Commission-approved independent system operators and regional transmission organizations.*

(1) *Demand response and pricing.*

(i) *Ancillary services provided by demand response resources.*

(A) Every Commission-approved independent system operator or regional transmission organization that operates organized markets based on competitive bidding for energy imbalance, spinning reserves, supplemental reserves, reactive power and voltage control, or regulation and frequency response ancillary services (or its functional equivalent in the Commission-approved independent system operator's or regional transmission organization's tariff) must accept bids from demand response resources in these markets for that product on a basis comparable to any other resources, if the demand response resource meets the necessary technical requirements under the tariff, and submits a bid under the Commission-approved independent system operator's or regional transmission organization's bidding rules at or below the market-clearing price, unless not permitted by the laws or regulations of the relevant electric retail regulatory authority.

(B) Each Commission-approved independent system operator or regional transmission organization must allow providers of a demand response resource to specify the following in their bids:

(*1*) A maximum duration in hours that the demand response resource may be dispatched;

(*2*) A maximum number of times that the demand response resource may be dispatched during a day; and

(*3*) A maximum amount of electric energy reduction that the demand response resource may be required to provide either daily or weekly.

(ii) *Removal of deviation charges.* A Commission-approved independent system operator or regional transmission organization with a tariff that contains a day-ahead and a real-time market may not assess a charge to a purchaser of electric energy in its day-ahead market for purchasing less power in the real-time market during a real-time market period for which the Commission-approved independent system operator or regional transmission organization declares an operating reserve shortage or makes a generic request to reduce load to avoid an operating reserve shortage.

(iii) *Aggregation of retail customers.* Each Commission-approved independent system operator and regional transmission organization must permit a qualified aggregator of retail customers to bid demand response on behalf of retail customers directly into the Commission-approved independent system operator's or regional transmission organization's organized markets, unless the laws and regulations of the relevant electric retail regulatory authority expressly do not permit a retail customer to participate.

(iv) *Price formation during periods of operating reserve shortage.*

(A) Each Commission-approved independent system operator or regional transmission organization must modify its market rules to allow the market-clearing price during periods of operating reserve shortage to reach a level that rebalances supply and demand so as to maintain reliability while providing sufficient provisions for mitigating market power.

(B) A Commission-approved independent system operator or regional transmission organization may phase in this modification of its market rules.

(2) *Long-term power contracting in organized markets.* Each Commission-approved independent system operator or regional transmission organization must provide a portion of its Web site for market participants to post offers to buy or sell power on a long-term basis.

(3) *Market monitoring policies.*

(i) Each Commission-approved independent system operator or regional transmission organization must modify its tariff provisions governing its Market Monitoring Unit to reflect the directives provided in Order No. 719, including the following:

(A) Each Commission-approved independent system operator or regional transmission organization must include in its tariff a provision to provide its Market Monitoring Unit access to Commission-approved independent system operator and regional transmission organization market data, resources and personnel to enable the Market Monitoring Unit to carry out its functions.

(B) The tariff provision must provide the Market Monitoring Unit complete access to the Commission-approved independent system operator's and regional transmission organization's databases of market information.

(C) The tariff provision must provide that any data created by the Market Monitoring Unit, including, but not limited to, reconfiguring of the Commission-approved independent system operator's and regional transmission organization's data, will be kept within the exclusive control of the Market Monitoring Unit.

(D) The Market Monitoring Unit must report to the Commission-approved independent system operator's or regional transmission organization's board of directors, with its management members removed, or to an independent committee of the Commission-approved independent system operator's or regional transmission organization's board of directors. A Commission-approved independent system operator or regional transmission organization that has both an internal Market Monitoring Unit and an external Market Monitoring Unit may permit the internal Market Monitoring Unit to report to management and the external Market Monitoring Unit to report to the Commission-approved independent system operator's or regional transmission organization's board of directors with its management members removed, or to an independent committee of the Commission-approved independent system operator or regional transmission organization board of directors. If the internal market monitor is responsible for carrying out any or all of the core Market Monitoring Unit functions identified in paragraph (g)(3)(ii) of this section, the internal market monitor must report to the independent system operator's or regional transmission organization's board of directors.

(E) A Commission-approved independent system operator or regional transmission organization may not alter the reports generated by the Market Monitoring Unit, or dictate the conclusions reached by the Market Monitoring Unit.

(F) Each Commission-approved independent system operator or regional transmission organization must consolidate the core Market Monitoring Unit provisions into one section of its tariff. Each independent system operator or regional transmission organization must include a mission statement in the introduction to the Market Monitoring Unit provisions that identifies the Market Monitoring Unit's goals, including the protection of consumers and market participants by the identification and reporting of market design flaws and market power abuses.

(ii) *Core Functions of Market Monitoring Unit.* The Market Monitoring Unit must perform the following core functions:

(A) Evaluate existing and proposed market rules, tariff provisions and market design elements and recommend proposed rule and tariff changes to the Commission-approved independent system operator or regional transmission organization, to the Commission's Office of Energy Market Regulation staff and to other interested entities such as state commissions and market participants, provided that:

(*1*) The Market Monitoring Unit is not to effectuate its proposed market design itself, and

(*2*) The Market Monitoring Unit must limit distribution of its identifications and recommendations to the independent system operator or regional transmission organization and to Commission staff in the event it believes broader dissemination could lead to exploitation, with an explanation of why further dissemination should be avoided at that time.

(B) Review and report on the performance of the wholesale markets to the Commission-approved independent system operator or regional transmission organization, the Commission, and other interested entities such as state commissions and market participants, on at least a quarterly basis and submit a more comprehensive annual state of the market report. The Market Monitoring Unit may issue additional reports as necessary.

(C) Identify and notify the Commission's Office of Enforcement staff of instances in which a market participant's or the Commission-approved independent system operator's or regional transmission organization's behavior may require investigation, including, but not limited to, suspected Market Violations.

(iii) *Tariff administration and mitigation*

(A) A Commission-approved independent system operator or regional transmission organization may not permit its Market Monitoring Unit, whether internal or external, to participate in the administration of the Commission-approved independent system operator's or regional transmission organization's tariff or, except as provided in paragraph (g)(3)(iii)(D) of this section, to conduct prospective mitigation.

(B) A Commission-approved independent system operator or regional transmission organization may permit its Market Monitoring Unit to provide the inputs required for the Commission-approved independent system operator or regional transmission organization to conduct prospective mitigation, including, but not limited to, reference levels, identification of system constraints, and cost calculations.

(C) A Commission-approved independent system operator or regional transmission organization may allow its Market Monitoring Unit to conduct retrospective mitigation.

(D) A Commission-approved independent system operator or regional transmission organization with a hybrid Market Monitoring Unit structure may permit its internal market monitor to conduct prospective and/or retrospective mitigation, in which case it must assign to its external market monitor the responsibility and the tools to monitor the quality and appropriateness of the mitigation.

(E) Each Commission-approved independent system operator or regional transmission organization must identify in its tariff the functions the Market Monitoring Unit will perform and the functions the Commission-approved independent system operator or regional transmission organization will perform.

(iv) *Protocols on Market Monitoring Unit referrals to the Commission of suspected violations.*

(A) A Market Monitoring Unit is to make a non-public referral to the Commission in all instances where the Market Monitoring Unit has reason to believe that a Market Violation has occurred. While the Market Monitoring Unit need not be able to prove that a Market Violation has occurred, the Market Monitoring Unit is to provide sufficient credible information to warrant further investigation by the Commission. Once the Market Monitoring Unit has obtained sufficient credible information to warrant referral to the Commission, the Market Monitoring Unit is to immediately refer the matter to the Commission and desist from independent action related to the alleged Market Violation. This does not preclude the Market Monitoring Unit from continuing to monitor for any repeated instances of the activity by the same or other entities, which would constitute new Market Violations. The Market Monitoring Unit is to respond to requests from the Commission for any additional information in connection with the alleged Market Violation it has referred.

(B) All referrals to the Commission of alleged Market Violations are to be in writing, whether transmitted electronically, by fax, mail, or courier. The Market Monitoring Unit may alert the Commission orally in advance of the written referral.

(C) The referral is to be addressed to the Commission's Director of the Office of Enforcement, with a copy also directed to both the Director of the Office of Energy Market Regulation and the General Counsel.

(D) The referral is to include, but need not be limited to, the following information.

(*1*) The name[s] of and, if possible, the contact information for, the entity[ies] that allegedly took the action[s] that constituted the alleged Market Violation[s];

(*2*) The date[s] or time period during which the alleged Market Violation[s] occurred and whether the alleged wrongful conduct is ongoing;

(*3*) The specific rule or regulation, and/or tariff provision, that was allegedly violated, or the nature of any inappropriate dispatch that may have occurred;

(*4*) The specific act[s] or conduct that allegedly constituted the Market Violation;

(*5*) The consequences to the market resulting from the acts or conduct, including, if known, an estimate of economic impact on the market;

(*6*) If the Market Monitoring Unit believes that the act[s] or conduct constituted a violation of the anti-manipulation rule of Part 1c, a description of the alleged manipulative effect on market prices, market conditions, or market rules;

(*7*) Any other information the Market Monitoring Unit believes is relevant and may be helpful to the Commission.

(E) Following a referral to the Commission, the Market Monitoring Unit is to continue to notify and inform the Commission of any information that the Market Monitoring Unit learns of that may be related to the referral, but the Market Monitoring Unit is not to undertake any investigative steps regarding the referral except at the express direction of the Commission or Commission Staff.

(v) *Protocols on Market Monitoring Unit Referrals to the Commission of Perceived Market Design Flaws and Recommended Tariff Changes.*

(A) A Market Monitoring Unit is to make a referral to the Commission in all instances where the Market Monitoring Unit has reason to believe market design flaws exist that it believes could effectively be remedied by rule or tariff changes. The Market Monitoring Unit must limit distribution of its identifications and recommendations to the independent system operator or regional transmission organization and to the Commission in the event it believes broader dissemination could lead to exploitation, with an explanation of why further dissemination should be avoided at that time.

(B) All referrals to the Commission relating to perceived market design flaws and recommended tariff changes are to be in writing, whether transmitted electronically, by fax, mail, or courier. The Market Monitoring Unit may alert the Commission orally in advance of the written referral.

(C) The referral should be addressed to the Commission's Director of the Office of Energy Market Regulation, with copies directed to both the Director of the Office of Enforcement and the General Counsel.

(D) The referral is to include, but need not be limited to, the following information.

(*1*) A detailed narrative describing the perceived market design flaw[s];

(*2*) The consequences of the perceived market design flaw[s], including, if known, an estimate of economic impact on the market;

(*3*) The rule or tariff change(s) that the Market Monitoring Unit believes could remedy the perceived market design flaw;

(*4*) Any other information the Market Monitoring Unit believes is relevant and may be helpful to the Commission.

(E) Following a referral to the Commission, the Market Monitoring Unit is to continue to notify and inform the Commission of any additional information regarding the perceived market design flaw, its effects on the market, any additional or modified observations concerning the rule or tariff changes that could remedy the perceived design flaw, any recommendations made by the Market Monitoring Unit to the regional transmission organization or independent system operator, stakeholders, market participants or state commissions regarding the perceived design flaw, and any actions taken by the regional transmission organization or independent system operator regarding the perceived design flaw.

(vi) *Market Monitoring Unit ethics standards.* Each Commission-approved independent system operator or regional transmission organization must include in its tariff ethical standards for its Market Monitoring Unit and the employees of its Market Monitoring Unit. At a minimum, the ethics standards must include the following requirements:

(A) The Market Monitoring Unit and its employees must have no material affiliation with any market participant or affiliate.

(B) The Market Monitoring Unit and its employees must not serve as an officer, employee, or partner of a market participant.

(C) The Market Monitoring Unit and its employees must have no material financial interest in any market participant or affiliate with potential exceptions for mutual funds and non-directed investments.

(D) The Market Monitoring Unit and its employees must not engage in any market transactions other than the performance of their duties under the tariff.

(E) The Market Monitoring Unit and its employees must not be compensated, other than by the Commission-approved independent system operator or regional transmission organization that retains or employs it, for any expert witness testimony or other commercial services, either to the Commission-approved independent system operator or regional transmission organization or to any other party, in connection with any legal or regulatory proceeding or commercial transaction relating to the Commission-approved independent system operator or regional transmission organization or to the Commission-approved independent system operator's or regional transmission organization's markets.

(F) The Market Monitoring Unit and its employees may not accept anything of value from a market participant in excess of a *de minimis* amount.

(G) The Market Monitoring Unit and its employees must advise a supervisor in the event they seek employment with a market participant, and must disqualify themselves from participating in any matter that would have an effect on the financial interest of the market participant.

(4) *Offer and bid data.* (i) Unless a Commission-approved independent system operator or regional transmission organization obtains Commission approval for a different period, each Commission-approved independent system operator and regional transmission organization must release its offer and bid data within three months.

(ii) A Commission-approved independent system operator or regional transmission organization must mask the identity of market participants when releasing offer and bid data. The Commission-approved independent system operators and regional transmission organization may propose a time period for eventual unmasking.

(5) *Responsiveness of Commission-approved independent system operators and regional transmission organizations.* Each Commission-approved independent system operator or regional transmission organization must adopt business practices and procedures that achieve Commission-approved independent system operator and regional transmission organization board of directors' responsiveness to customers and other stakeholders and satisfy the following criteria:

(i) *Inclusiveness.* The business practices and procedures must ensure that any customer or other stakeholder affected by the operation of the Commission-approved independent system operator or regional transmission organization, or its representative, is permitted to communicate the customer's or other stakeholder's views to the independent system operator's or regional transmission organization's board of directors;

(ii) *Fairness in balancing diverse interests.* The business practices and procedures must ensure that the interests of customers or other stakeholders are equitably considered, and that deliberation and consideration of Commission-approved independent system operator's and regional transmission organization's issues are not dominated by any single stakeholder category;

(iii) *Representation of minority positions.* The business practices and procedures must ensure that, in instances where stakeholders are not in total agreement on a particular issue, minority positions are communicated to the Commission-approved independent system operator's and regional transmission organization's board of directors at the same time as majority positions; and

(iv) *Ongoing responsiveness.* The business practices and procedures must provide for stakeholder input into the Commission-approved independent system operator's or regional transmission organization's decisions as well as mechanisms to provide feedback to stakeholders to ensure that information exchange and communication continue over time.

(6) *Compliance filings.* All Commission-approved independent system operators and regional transmission organizations must make a compliance filing with the Commission as described in Order No. 719 under the following schedule:

(i) The compliance filing addressing the accepting of bids from demand response resources in markets for ancillary services on a basis comparable to other resources, removal of deviation charges, aggregation of retail customers, shortage pricing during periods of operating reserve shortage, long-term power contracting in organized markets, Market Monitoring Units, Commission-approved independent system operators' and regional transmission organizations' board of directors' responsiveness, and reporting on the study of the need for further reforms to remove barriers to comparable treatment of demand response resources must be submitted on or before April 28, 2009.

(ii) A public utility that is approved as a regional transmission organization under § 35.34, or that is not approved but begins to operate regional markets for electric energy or ancillary services after December 29, 2008, must comply with Order No. 719 and the provisions of paragraphs (g)(1) through (g)(5) of this section before beginning operations.

Note: The following appendix will not be published in the *Code of Federal Regulations*.

Appendix—Abbreviated Names of Commenters

Alcoa—Alcoa, Inc.
Ameren—Ameren Services Company
American Forest—American Forest & Paper Association
AMPA—Arkansas Municipal Power Association
APPA—American Public Power Association
ATC—American Transmission Company, LLC
Beacon Power—Beacon Power Corporation
Blue Ridge—Blue Ridge Power Agency
BlueStar Energy—BlueStar Energy Services, Inc.
Mr. Borlick—Robert L. Borlick, Borlick & Associates
BP Energy—BP Energy Company
CAISO—California Independent System Operator Corporation
California DWR—California Department of Water Resources State Water Project
California Munis—California Municipal Utilities Association
California PUC—Public Utilities Commission of the State of California
Cogeneration Parties—Energy Producers and Users Coalition (EPUC) and the Cogeneration Association of California (CAC). EPUC is an *ad hoc* group representing the end-use and customer generation interests of the following: Aera Energy LLC; BP America, Inc. (including Atlantic Richfield Company); Chevron U.S.A., Inc.; ConocoPhillips Company; ExxonMobil Power and Gas Services, Inc.; Shell Oil Products US; THUMS Long Beach Company; Occidental Elks Hills, Inc.; and Valero Refining Company-California. CAC is an *ad hoc* association representing the power generation, power marketing and cogeneration operation interests of the following: Coalinga Cogeneration Company, Mid-Set Cogeneration Company, Kern River Cogeneration Company, Sycamore Cogeneration Company, Sargent Canyon Cogeneration Company, Salinas River Cogeneration Company, Midway Sunset Cogeneration Company and Watson Cogeneration Company.
Comverge—Comverge, Inc.
Connecticut and Massachusetts Municipals—Connecticut Municipal Electric Energy Cooperative and Massachusetts Municipal Wholesale Electric Company
Constellation—Constellation Energy Commodities Group, Inc., Constellation NewEnergy, Inc., and Constellation Power Source Generation, Inc.
DC Energy—DC Energy, LLC
Detroit Edison—Detroit Edison Company
Dominion Resources—Dominion Resources Services

DRAM—Demand Response and Advanced Metering Coalition
Duke Energy—Duke Energy Corporation
EEI—Edison Electric Institute
EnergyConnect—EnergyConnect, Inc.
Energy Curtailment—Energy Curtailment Specialists, Inc.
EnerNOC—EnerNOC, Inc.
E.ON U.S.—E.ON U.S. LLC
EPSA—Electric Power Supply Association
Exelon—Exelon Corporation
FTC—Federal Trade Commission
FirstEnergy—FirstEnergy Service Company, on behalf of FirstEnergy Solutions Corp. and the transmission- and distribution-owning utility subsidiaries of FirstEnergy Corp.: American Transmission Systems, Incorporated; The Cleveland Electric Illuminating Company; Jersey Central Power and Light Company; Metropolitan Edison Company; Ohio Edison Company; Pennsylvania Electric Company; Pennsylvania Power Company; and The Toledo Edison Company
IID—Imperial Irrigation District
IMEA—Illinois Municipal Electric Agency
Indianapolis P&L—Indianapolis Power and Light Company
Industrial Coalitions—The Coalition of Midwest Transmission Customers, Connecticut Industrial Energy Consumers, Industrial Energy Consumers of Pennsylvania, NEPOOL Industrial Customer Coalition, Industrial Energy Users-Ohio, West Virginia Energy Users Group, PJM Industrial Customer Coalition, American Iron and Steel Institute, and Portland Cement Association
Industrial Consumers—Electricity Consumers Resource Council, American Chemistry Council, American Iron and Steel Institute, Association of Businesses Advocating Tariff Equity, Council of Industrial Boiler Owners, and Wisconsin Industrial Energy Group
Integrys Energy—Integrys Energy Services, Inc.
ISO New England—ISO New England Inc.
ISO/RTO Council—ISO/RTO Council, which is comprised of the Alberta Electric System Operator; California Independent System Operator, Inc.; New Brunswick System Operator; Electric Reliability Council of Texas; Independent Electricity System Operator of Ontario; ISO New England Inc.; Midwest Independent Transmission System Operator, Inc.; New York Independent System Operator, Inc.; PJM Interconnection, LLC; and Southwest Power Pool, Inc.
ITC—International Transmission Company; Michigan Electric Transmission Company, LLC; and ITC Midwest LLC
Joint Commenters—Citadel Energy Products LLC, Citadel Energy Strategies LLC, Citadel Energy Investments Ltd.; and DC Energy LLC
Kansas CC—Kansas Corporation Commission
LPPC—Large Public Power Council
MADRI States—the State members of the Mid-Atlantic Distributed Resources Initiative
Maine PUC—Maine Public Utilities Commission
Midwest Energy—Midwest Energy, Inc.
Midwest ISO—Midwest Independent Transmission System Operator, Inc.
Midwest ISO TOs—Midwest ISO Transmission Owners: Ameren Services Company, as agent for Union Electric Company d/b/a AmerenUE, Central Illinois Public Service Company d/b/a AmerenCIPS, Central Illinois Light Co. d/b/a AmerenCILCO, and Illinois Power Company d/b/a AmerenIP; City of Columbia Water and Light Department (Columbia, Missouri); City Water, Light & Power (Springfield, Illinois); Duke Energy Shared Services for Duke Energy Ohio, Inc., Duke Energy Indiana, Inc., and Duke Energy Kentucky, Inc.; Great River Energy; Hoosier Energy Rural Electric Cooperative, Inc.; Indiana Municipal Power Agency; Indianapolis Power & Light Company; Manitoba Hydro; Michigan Public Power Agency; Minnesota Power (and its subsidiary Superior Water, L&P); Montana-Dakota Utilities Co.; Northern Indiana Public Service Company; Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin corporation, subsidiaries of Xcel Energy Inc.; Northwestern Wisconsin Electric Company; Otter Tail Power Company; Southern Illinois Power Cooperative; Southern Indiana Gas & Electric Company (d/b/a Vectren Energy Delivery of Indiana); Southern Minnesota Municipal Power Agency; Wabash Valley Power Association, Inc.; and Wolverine Power Supply Cooperative, Inc.
NARUC—National Association of Regulatory Commissioners
National Grid—National Grid USA and its affiliates
NCPA—Northern California Power Agency
NEPGA—New England Power Generators Association, Inc.
NEPOOL Participants—New England Power Pool Participants Committee
New England Power Generators—New England Power Generators Association, Inc.
New York PSC—New York State Public Service Commission
NIPSCO—Northern Indiana Public Service Company
New Jersey BPU—New Jersey Board of Public Utilities
North Carolina Electric Membership—North Carolina Electric Membership Corporation
Northeast Utilities—Northeast Utilities
NRECA—National Rural Electric Cooperative Association
NSTAR—NSTAR Electric Company
NYISO—New York Independent System Operator, Inc.
NY TOs—Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., Long Island Power Authority, New York Power Authority, New York State Electric & Gas Corporation, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation
Ohio PUC—Public Utilities Commission of Ohio
Old Dominion—Old Dominion Electric Cooperative
OMS—Organization of MISO States, whose participating members are: Illinois Commerce Commission, Indiana Utility Regulatory Commission, Iowa Utilities Board, Kentucky Public Service Commission, Michigan Public Service Commission, Minnesota Public Utilities Commission, Montana Public Service Commission, Nebraska Power Review Board, Public Utilities Commission of Ohio, South Dakota Public Utilities Commission, Wisconsin Public Service Commission. Participating associate members are: Indiana Office of Utility Consumer Counselor, Iowa Office of Consumer Advocate and the Minnesota Office of Energy Security
OPSI—Organization of PJM States, Inc., whose state commission members include: Delaware Public Service Commission, District of Columbia Public Service Commission, Illinois Commerce Commission, Indiana Utility Regulatory Commission, Kentucky Public Service Commission, Maryland Public Service Commission, Michigan Public Service Commission, New Jersey Board of Public Utilities, North Carolina Utilities Commission, Public Utilities Commission of Ohio, Pennsylvania Public Utility Commission, Tennessee Regulatory Authority, Virginia State Corporation Commission, and Public Service Commission of West Virginia
Orion Energy—Orion Energy Systems, Inc.
Pennsylvania PUC—Pennsylvania Public Utility Commission
PG&E—Pacific Gas and Electric Company
PJM—PJM Interconnection, LLC
PJM Power Providers—PJM Power Providers Group
Potomac Economics—Potomac Economics, Ltd.
PPL Parties—PPL Brunner Island, LLC; PPL Edgewood Energy, LLC; PPL Electric Utilities Corporation; PPL EnergyPlus, LLC; PPL Great Works, LLC; PPL Holtwood, LLC; PPL Maine, LLC; PPL Martins Creek, LLC; PPL Montana, LLC; PPL Montour, LLC; PPL Shoreham Energy, LLC; PPL Susquehanna, LLC; PPL University Park, LLC; PPL Wallingford Energy LLC; and Lower Mount Bethel Energy, LLC
Public Interest Organizations—Citizen Power; Conservation Law Foundation; Environment Northeast; Environmental Law & Policy Center; Fresh Energy; Izaak Walton League; Natural Resources Defense Council; Northwest Energy Coalition; Office of the Ohio Consumers' Counsel; Pace Energy Project; PennFuture; Project for Sustainable FERC Energy Policy; Southern Alliance for Clean Energy; The Stella Group, Ltd.; Union of Concerned Scientists; and Western Grid Group
Reliant—Reliant Energy, Inc.
Retail Energy—Retail Energy Supply Association
SMUD—Sacramento Municipal Utility District
SoCal Edison-SDG&E—Southern California Edison Company and San Diego Gas & Electric Company
Sorgo—Sorgo Fuels, Inc.
SPP—Southwest Power Pool, Inc.
Steel Manufacturers—Steel Manufacturers Association
Steel Producers—Nucor and Steel Dynamics
TANC—Transmission Agency of Northern California

TAPS—Transmission Access Policy Study Group

Wal-Mart—Wal-Mart Stores, Inc.

Xcel—Xcel Energy Services, Inc., on behalf of Northern States Power Company, a Minnesota corporation; Northern States Power Company, a Wisconsin corporation; Southwestern Public Service Company; and Public Service Company of Colorado

Abbreviated Names of Reply Commenters

Allied Public Interest Groups—Clean Energy First, Conservation Law Foundation, Environment Northeast, Environmental Law & Policy Center, Fresh Energy, Natural Resources Defense Council, Northwest Energy Coalition, Office of the Ohio Consumers' Counsel, Pace Energy and Climate Center, Penn Future, Project for Sustainable FERC Energy Policy, Renewable Northwest Project, and Union of Concerned Scientists.

CAISO and the Cities—CAISO and the cities of Anaheim, Azusa, Banning, Colton, and Riverside, California

UNITED STATES OF AMERICA

FEDERAL ENERGY REGULATORY COMMISSION

Wholesale Competition in Regions with Organized Electric Markets

Docket Nos. RM07–19–000 and AD07–7–000

(Issued October 17, 2008)

KELLY, Commissioner, *concurring in part and dissenting in part:*

I write separately for two reasons. First, I want to emphasize the importance of competition to the operation of organized wholesale electric markets and the fact that many of the findings here will help foster that competition. Second, I write to express my misgivings about the potential impacts of several of the directives included in the Final Rule.

I believe that many of the Final Rule's findings will promote competition, thereby helping the Commission to fulfill our statutory mandate to ensure adequate and reliable service at just and reasonable rates. In particular, I support the Final Rule's requirements that regional transmission organizations (RTOs) and independent system operators (ISOs): (1) Accept bids for certain ancillary services from demand response resources that meet technical requirements and submit a bid at or below the market-clearing price; (2) permit qualified aggregators of retail customers to bid demand response on behalf of retail customers; and (3) eliminate deviation charges during system emergencies to a purchaser of electric energy for taking less energy in the real-time market than it purchased in the day-ahead market. I also agree with requiring RTOs/ISOs to include a tariff provision that commits to providing market monitoring units (or MMUs) with the data, resources, and personnel necessary to carry out the MMUs' functions.

I continue to be troubled by the Final Rule's directive to each RTO or ISO with an organized energy market to make a compliance filing to propose any necessary reforms to allow for scarcity pricing in times of emergency by modifying market power mitigation rules. The Final Rule states that existing RTO/ISO rules ''may not produce prices that accurately reflect the value of energy and, by failing to do so, may harm reliability, inhibit demand response, deter entry of demand response and generation resources, and thwart innovation.'' I recognize that the majority has good intentions in requiring RTOs/ISOs to make this filing. However, I believe that, prior to allowing energy supply offer caps and demand bid caps to rise or be eliminated, the necessary generation and demand response infrastructure must be in place to give consumers the ability to respond to higher prices. As Commission staff noted in the *2006 FERC Staff Demand Response Assessment*, advanced metering currently has low market penetration of less than six percent in the United States.[1] Without providing consumers with the ability to respond to rising prices, I view the decision to allow energy supply offer caps and demand bid caps to rise or be eliminated as irresponsible.

Additionally, I disagree with the Final Rule's decision to promote responsiveness of RTOs/ISOs by allowing them to adopt hybrid boards with stakeholder members. Having an independent board is the cornerstone of RTO/ISO policy. Providing for stakeholder representatives on an RTO/ISO board jeopardizes such an independent governing structure. I agree with Duke Energy's statement that ''hybrid boards are contrary to the premise of independent RTO governance, and that the board advisory committee is a much more effective means of helping RTO boards to understand member issues and concerns.'' [2] I also fear that a board with independent and non-independent members will suffer from a divisive atmosphere with suspicion as to whether non-independent board members are acting in the best interests of the RTO/ISO and its customers or in the best interest of the particular market participant represented by that non-independent board member. I also share Pennsylvania PUC's concern that it will be difficult to protect competitively sensitive information with non-independent members serving on the RTO/ISO's board.[3] I believe that a board advisory committee is a better way to address RTO/ISO responsiveness to stakeholders while maintaining the independence of RTO/ISO boards.

Finally, as I noted previously in my separate statement regarding the notice of proposed rulemaking (NOPR),[4] I am concerned about the issue of MMUs being removed from tariff administration and mitigation. I note that a large number and variety of commenters were also concerned about the NOPR proposal, including American Forest, California PUC, Indianapolis P&L, ISO New England, Industrial Coalitions, Maine PUC, NARUC, NEPOOL Participants, New York PSC, North Carolina Electric Membership, Ohio PUC, Old Dominion, OMS, Potomac Economics, and Xcel. ISO New England stated that it ''disagrees with the proposition that an MMU's performance of mitigation functions compromises the MMU's independence or distracts an MMU from its core functions,'' [5] referring to the arguments against MMUs' involvement in mitigation as ''unconvincing.'' [6] Maine PUC stated that ''[t]he Commission has not demonstrated that there is a lack of independence or a conflict of interest in having those who are experts in the areas of market mitigation performing day-to-day mitigation.'' [7] Industrial Coalitions called the Commission's proposal, ''objectionable because it would place responsibility for mitigation in the hands of the RTO/ISO staff that designed, and have a vested interest in the success of, market rules.'' [8]

I do not mean to imply that the Final Rule totally ignores these concerns. Indeed, the Final Rule does make changes to the NOPR proposal by drawing a distinction between RTOs/ISOs that have a single MMU and those that have hybrid MMUs, with both an ''external'' and ''internal'' market monitor. Under these changes, a RTO/ISO may allow its MMU—whether it is a single MMU or a hybrid MMU—to perform retrospective mitigation. However, only a RTO/ISO with both an internal and external MMU may allow its internal MMU to continue to perform prospective mitigation.[9] In those instances, the internal MMU may perform the prospective mitigation, but only if the RTO/ISO moves the responsibility and the tools to monitor the quality and appropriateness of the mitigation conducted by the internal MMU to its external MMU. Finally, both single MMUs and hybrid MMUs may provide the RTO/ISO with the inputs needed for the RTO/ISO to conduct prospective mitigation, including ''reference levels, identification of system constraints, and cost calculations.''

After this long, drawn-out process, I question what problem we are actually trying to solve with this proposal. MMUs are professionals who have been performing mitigation in a competent, professional, and efficient manner for many years. I disagree with the misgivings expressed in the Final Rule that ''unfettered conduct of mitigation by MMUs makes them subordinate to the RTOs and ISOs and raises conflict of interest concerns.'' I do not think the record supports

[1] Assessment of Demand Response and Advanced Metering: Staff Report, Docket No. AD06–2–000, at 26 (2006) (*2006 FERC Staff Demand Response Assessment*).

[2] Duke Energy Corporation Apr. 21, 2008 Comments, Docket No. RM07–19, at 2;–3.

[3] *See* Pennsylvania PUC Apr. 21, 2008 Comments, Docket No. RM07–19, at 18.

[4] *Wholesale Competition in Regions with Organized Electric Markets*, Notice of Proposed Rulemaking, 73 FR 12,576 (Mar. 7, 2008), FERC Stats. & Regs. ¶ 32,628 (2008) (Comm'r Kelly concurring in part and dissenting in part).

[5] ISO New England Apr. 21, 2008 Comments, Docket No. RM07–19, at 19.

[6] *Id.*

[7] Maine PUC Apr. 21, 2008 Comments, Docket No. RM07–19, at 7.

[8] Industrial Coalitions Apr. 21, 2008 Comments, Docket No. RM07–19, at 22.

[9] The Final Rule considers prospective mitigation to include mitigation that can affect market outcomes on a forward-going basis, such as altering the prices of offers or altering the physical parameters of offers at or before the time they are considered in a market solution.

that assertion. I am also concerned that the dictates of the Final Rule may put some RTOs/ISOs to unnecessary expense. While the Final Rule has evolved in a positive way on this issue, I believe it continues to be an answer in search of a problem.

Accordingly, for the reasons stated above, I concur in part and dissent in part on this Final Rule.

Suedeen G. Kelly

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