No. 14-

IN THE

Supreme Court of the United States

ENERNOC, INC. *et al.*,

Petitioners,

v.

ELECTRIC POWER SUPPLY ASSOCIATION, *et al.*,

Respondents.

On Petition for a Writ of Certiorari to the United States Court of Appeals for the District of Columbia Circuit

PETITION FOR A WRIT OF CERTIORARI

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QUESTION PRESENTED

Whether the Federal Energy Regulatory Commission's jurisdiction over interstate markets for wholesale sales of electric energy under sections 201, 205 and 206 of the Federal Power Act, 16 U.S.C. §§ 824(b)(1), 824d and 824e, provides the Commission with authority to regulate participation in those markets by demand response resources?

PARTIES TO THE PROCEEDING AND RULE 29.6 STATEMENT

Parties to the proceeding below:

American Forest & Paper Association
American Municipal Power, Inc.
American Public Power Association
California Public Utilities Commission
California Independent System Operator Corporation
Coalition of MISO Transmission Customers
Edison Electric Institute
Electric Power Supply Association
EnergyConnect, Inc.
EnerNOC, Inc.
Federal Energy Regulatory Commission
Lower Mount Bethel Energy, LLC
Madison Gas and Electric Company
Maryland Public Service Commission
Missouri Joint Municipal Electric Utility Commission
Missouri River Energy Services
National Rural Electric Cooperative Association
Old Dominion Electric Cooperative
Pennsylvania Public Utility Commission
PJM Industrial Customer Coalition
PJM Interconnection, LLC
PJM Power Providers Group
PPL Brunner Island, LLC
PPL Electric Utilities Corporation
PPL EnergyPlus, LLC
PPL Holtwood, LLC
PPL Maine, LLC
PPL Martins Creek, LLC
PPL Montour, LLC
PPL Susquehanna, LLC
PSEG Energy Resources & Trade LLC

PSEG Power LLC
Public Service Electric and Gas Company
Southern Minnesota Municipal Power Agency
Steel Producers
Viridity Energy, Inc.
Wal-Mart Stores, Inc.
WPPI Energy

Pursuant to Supreme Court Rule 29.6, Petitioners state as follows:

EnerNOC, Inc. is a publicly held corporation with no parent corporation. No publicly held corporation owns more than 10 percent of EnerNOC's stock.

Viridity Energy, Inc. is not a publicly held corporation and has no parent corporation.

EnergyConnect, Inc. is a wholly owned subsidiary of Johnson Controls, Inc. No publicly held company has a 10 percent or greater ownership interest in Johnson Controls, Inc.

No other Petitioner is a publicly held corporation or has a parent corporation.

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PETITION FOR A WRIT OF CERTIORARI

Petitioners respectfully seek a writ of certiorari to review the decision of the United States Court of Appeals for the District of Columbia Circuit.

OPINIONS BELOW

The court of appeals' opinion is reported at 753 F.3d 216, and reproduced in the Appendix ("App.") 1a-45a. The Federal Energy Regulatory Commission ("FERC") orders under review are Order 745, Final Rule, reported at 134 FERC ¶ 61,187 (2011), and Order 745-A, Order on Rehearing and Clarification, reported at 137 FERC ¶ 61,215 (2011). They are reproduced at App. 140a-253a and App. 46a-139a, respectively.

JURISDICTION

The court of appeals entered judgment on May 23, 2014, App. 1a, and denied all petitions for rehearing on September 17, 2014, *id.* at 254a-255a. It stayed the issuance of its mandate until December 16, 2014, and extended that stay to January 15, 2015, and thereafter if a petition for certiorari is filed by that date. *Id.* at 256a-259a. The Chief Justice granted petitioners' application for an extension of time to file a petition for certiorari to and including January 15, 2015. This Court has jurisdiction under 28 U.S.C. § 1254(1).

STATUTORY PROVISIONS INVOLVED

The statutes involved are the Federal Power Act ("FPA"), sections 201, 205 and 206, 16 U.S.C. §§ 824, 824d and 824e, and section 2642 of the Energy Policy Act of 2005 ("EPAct"). The regulation involved is 18

C.F.R. § 35.28. All are set forth in the Appendix. App. 260a-298a.

INTRODUCTION

Unless reviewed and reversed, the decision below will have profound and negative implications for U.S. wholesale energy markets. The decision holds that FERC lacks authority to adopt regulations that not only help ensure that rates in wholesale energy markets are just and reasonable, but also reduce wholesale energy prices and enhance the reliability of the nation's interconnected electric grid. Because of the importance of this issue, and because only this Court can restore FERC's ability to regulate the sale of wholesale energy effectively, the petition should be granted.

The FPA grants FERC authority to regulate both "the sale of electric energy at wholesale in interstate commerce," and "any ... practice ... affecting" wholesale rates. 16 U.S.C. §§ 824(b)(1), 824e(a). FERC thus has jurisdiction relating to the organized wholesale energy markets that are administered by the FERC-approved Regional Transmission Organizations ("RTOs") and Independent System Operators ("ISOs") whose interstate systems cover more than half the nation.

In a series of orders over the past decade, FERC sought to eliminate barriers precluding firms that aggregate contractual commitments to reduce demand – also known as "demand response resources" – from entering the wholesale electricity markets and competing with electric power generators. FERC found that regulation of RTOs' and ISOs' purchases of demand response was necessary to ensure just, reasonable and non-discriminatory wholesale rates. FERC also explained that regulating these purchases would directly affect (lower) wholesale prices, enhance system reliability, and encourage technological innovation. Moreover, FERC found that absent regulatory oversight, there would be an insufficient quantity of demand response resources available to RTOs and ISOs, which would result in higher wholesale prices and decreased grid reliability.

FERC's efforts have borne fruit. Numerous, innovative companies have entered the marketplace allowing an array of industrial and commercial businesses, schools and universities, hospitals, and governmental agencies to sell their demand-side flexibility as a service in wholesale markets. Petitioners EnerNOC, EnergyConnect (a subsidy of Johnson Controls) and Viridity are such companies; they have invested heavily to develop software and monitoring equipment that allow their customers in the aggregate to substantially lower their electricity usage at times of peak pricing in the wholesale energy market.

In the decision below, however, a divided panel of the D.C. Circuit held that FERC lacks jurisdiction to regulate the purchase of demand response resources in wholesale energy markets operated by RTOs and ISOs. The majority agreed that demand response has a significant impact in the wholesale energy market by "lower[ing] the wholesale price" and "increas[ing] system reliability." App. 7a. But it nonetheless concluded that FERC lacks jurisdiction on the theory that regulation involving demand response resources – even direct regulation of regional entities established by FERC operating interstate, wholesale energy markets where FERC has exclusive jurisdiction – necessarily involves "retail markets," where the states have exclusive jurisdiction. *Id.* at 7a-11a.

The D.C. Circuit incorrectly decided a critically important question about the scope of FERC's jurisdiction. Demand-side participation in organized wholesale energy markets has a direct and substantial impact on wholesale rates and system reliability, meaning that regulation of such participation is squarely within FERC's jurisdiction, as the FPA's text and this Court's cases make clear. The link between demand response participation and wholesale energy rates is too clear and immediate to raise any concern about a "limiting principle." App. 7a. The courts are fully capable of distinguishing regulation that directly and substantially affects wholesale rates from that which is too attenuated to warrant federal regulation.

FERC's authority is not displaced by the fact that states have exclusive jurisdiction over retail sales of electricity. FERC's decision to allow demand response resources to participate in wholesale energy markets does not regulate retail sales. Indeed, as Judge Edwards's dissent correctly explained, demand response is not a "sale of electricity" at all. And, as this Court's cases make clear, any indirect effect that FERC regulation has on the retail market does not divest FERC of authority to adopt regulations that operate directly on the wholesale market. Only direct federal regulation of matters the FPA expressly assigns to the states is out of bounds. Here, FERC is regulating jurisdictional entities – RTOs and ISOs – and regulating only the terms of their wholesale tariffs. FERC did not command a state to take any action. Nor did it set or invalidate a retail rate. The D.C. Circuit's decision cannot be reconciled with this Court's decisions defining the scope of FERC jurisdiction under the FPA.

The D.C. Circuit's decision also threatens FERC's ability to comply with Congress's mandate in the Energy Policy Act of 2005 that demand response participation in wholesale electricity markets should be encouraged. In fact, if allowed to stand, the court's decision will directly undermine Congress' energy policies: prices will rise as the result of the need to dispatch unnecessary and higher cost generation – costs that consumers will ultimately have to pay. At the same time, the court's decision threatens system reliability by depriving grid operators of an important resource that can balance system load when demand spikes or there is an unexpected loss of generation. And in the long run, energy innovation and technological advances will be stifled.

Petitioners are not "crying wolf," as demonstrated by the reaction from a broad spectrum of market participants, state regulators and other stakeholders, including consumer advocates, environmental organizations, high tech companies, large manufacturers, and commercial end-use consumers. This Court should grant the petition and reverse the D.C. Circuit's incorrect understanding of FERC's jurisdiction, to restore FERC's authority to regulate wholesale energy markets efficiently, and to prevent the substantial economic and technological damage the decision will cause.

STATEMENT OF THE CASE

Although the regulatory background in which this case arises is complex, the legal issues are straight forward. To put the case into context, we describe: 1) the evolution and operation of wholesale electricity markets; 2) what demand response resources are and how they participate in those markets; 3) the history of FERC's regulations relating to demand response resources' participation in wholesale markets, including the orders at issue, Orders 745 and 745-A; and 4) the D.C. Circuit's divided decision vacating those orders.

1. *Background.* During much of the 20th century, "most electricity was sold by vertically integrated utilities that had constructed their own power plants, transmission lines, and local delivery systems" to generate, transmit and sell electricity to end users. *New York v. FERC*, 535 U.S. 1, 5 (2002). These utilities "operated as separate, local monopolies subject to state or local regulation." *Id.* The states' regulatory power, however, was limited principally by the dormant Commerce Clause. *See Pub. Utils. Comm'n v. Attleboro Steam & Elec. Co.*, 273 U.S. 83, 89 (1927), *abrogated on other grounds by Ark. Elec. Coop. Corp. v. Ark. Pub. Serv. Comm'n*, 461 U.S. 375 (1983).

In 1935, Congress enacted the FPA, both to fill the regulatory gap created by the dormant Commerce Clause and to regulate the growing field of interstate electricity transmission and sales. The FPA gave the Federal Power Commission (and subsequently FERC) authority over the "transmission" and "sale of electric energy at wholesale" in interstate commerce. 16 U.S.C. § 824(b)(1). Federal regulation has grown in importance as technological advances have made it possible to generate and transmit electricity much more efficiently, and the energy market has shifted away from local monopolies to an interconnected system of interstate competition. *See New York*, 535 U.S. at 7.

In recent decades, instead of ensuring the reasonableness of interstate energy transactions by setting rates, FERC has chosen to do so by regulating interstate energy markets. As FERC explained, "[i]mproving the competitiveness of organized wholesale energy markets is ... integral to the Commission fulfilling its statutory mandate under the FPA to ensure supplies of electric energy at just, reasonable, and not unduly discriminatory or preferential rates." Order 745 ¶ 8.

Accordingly, over the years, FERC has taken a number of actions designed to strengthen competition in wholesale markets. *See New York*, 535 U.S. at 11-13. Relevant here, FERC concluded that "the development of regional markets is the best method of facilitating competition within the power industry." *Wholesale Competition in Regions with Organized Elec. Mkts.*, Order 719, 125 FERC ¶ 61,071, ¶ 10 (2008), *aff'd*, Order 719-A, 128 FERC ¶ 61,059 (2009). Thus, FERC authorized the creation of "'Regional Transmission Organizations [RTOs]'" and "'Independent System Operators [ISOs]'" to operate and oversee certain multistate systems and markets. *See Morgan Stanley Capital Grp., Inc. v. Pub. Util. Dist. No. 1*, 554 U.S. 527, 536 (2008). Generally speaking, RTOs and ISOs operate "the transmission facilities owned by member utilities. [They] 'provide open access to the regional transmission systems to all electricity generators at rates established in a single, unbundled, grid-wide tariff ....'" *NRG Power Mktg. LLC v. Me. Pub. Util. Comm'n*, 558 U.S. 165, 169 n.1 (2010).

Electricity markets administered by RTOs and ISOs are known as "organized markets." RTOs and ISOs operate one or more distinct competitive bidding markets comprising various elements of FERC jurisdictional electric service, including what are referred to as markets for "energy," "capacity," and certain transmission services (known as "ancillary services").[1] 18 C.F.R. §§ 35.2(a), 35.28(g)(1), 35.34(j)(2),

[1] "'Capacity' is not electricity itself but the ability to produce it when necessary. It amounts to a kind of call option that elec-

35.36 *et seq*. (Subpart H). This case involves demand response when it participates in organized wholesale energy markets. Relevant here, energy markets involve the sale and purchase of electricity for delivery within the next hour or the next 24 hours.

2. *Wholesale Energy Markets and Demand Response*. Electricity cannot yet be cost-effectively stored for later use at the wholesale level. As a result, to maintain reliable service, system operators (RTOs and ISOs) must ensure that the supply (sales) of electricity is continuously balanced with demand from the entities that buy wholesale electricity. The real-time and next-day bidding markets operated by RTOs and ISOs accomplish this by allowing wholesale prices to change rapidly in response to changes in demand. *See Wis. Pub. Power Inc. v. FERC*, 493 F.3d 239, 250 (D.C. Cir. 2007) (per curiam).

Some suppliers can offer electricity inexpensively, while others are more costly to operate. As the demand for electricity peaks (*e.g.*, during a heat wave), the system operator may be required to dispatch electricity from more costly suppliers to meet demand. At any given moment, the wholesale market price used to compensate *all* suppliers is the marginal cost of electricity, known as the locational market price ("LMP"). It is "designed to reflect the least-cost of

tricity transmitters purchase from parties – generally, generators – who can either produce more or consume less when required." *Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 479 (D.C. Cir. 2009). The ancillary services market, generally speaking, involves services that allow a grid operator to account for short-term increases or decreases in electric demand and to maintain system reliability. *See* EnerNOC, *What is an Ancillary Services Market*, http://www.enernoc.com/our-resources/term-pages/what-is-an-ancillary-services-market (last visited Jan. 7, 2015).

meeting an incremental megawatt-hour of demand at each location on the grid, and thus prices vary based on location and time." *Sacramento Mun. Util. Dist. v. FERC*, 616 F.3d 520, 524 (D.C. Cir. 2010) (per curiam); *see also* Order 745 ¶ 53. RTOs and ISOs calculate LMP differently, but "each method establishes the marginal value of resources in that market." Order 745 ¶ 2 n.5.

In a properly functioning market, the increasing cost of producing electricity during peak periods would promptly be reflected in higher prices for end users, and individuals or businesses therefore likely would reduce their consumption to save money. This does not happen, however, in the electricity market. Electricity prices charged to consumers, *i.e.*, retail prices, are not generally permitted to fluctuate hour-by-hour or even day-by-day. Demand typically does not respond to changes in the underlying price of electricity in the wholesale market. Order 745-A ¶¶ 59, 61; Order 745 ¶ 57; FERC, *A National Assessment of Demand Response Potential* 65-66, 189-90 (June 2009), *available at* http://www.ferc.gov/legal/staff-reports/06-09-demand-response.pdf. Thus, absent demand response in the wholesale market, electricity demand does not change based on wholesale price signals. Instead, "there has been overbuilding of plants that only run at peak hours," because a "strictly supply-side management strategy requires sufficient peaking capacity and reserve margins to reliably meet the highest load on hot summer days … plus a contingency for outages and other disruptive events." Joel Eisen, *Who Regulates the Smart Grid?*, 4 San Diego J. of Climate & Energy L. 69, 78 (2012-13).

The Commission long ago identified this problem. *See* Order 719 ¶ 18 & nn.17-18 (citing orders express-ing this concern). In Order 745-A, FERC reaffirmed that:

> [a] properly functioning market should reflect both the willingness of sellers to sell at a price and the willingness of buyers to purchase at a price. In an RTO- or ISO-run market, however, buyers are generally unable to directly express their willingness to pay for a product at the price offered. [Order 745-A ¶ 30].

As a result, FERC has encouraged the development of demand response and the participation of "demand response resources" in wholesale markets.

"Demand response" is not "energy"; instead, it is a mechanism designed to result in a reduction in electricity consumption. *See* 18 C.F.R. § 35.28(b)(4) (defining demand response as "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"). Electricity customers can, either individually in the case of large commercial or industrial customers, or in aggregate, provide a substantial amount of "demand response" without significantly affecting their comfort or their businesses (*e.g.*, if a service provider deploys software to enable real-time control of thermostats for air conditioners or hot water heaters).

It is simplistic, however, to think of demand response as individual customers flipping off a light switch or turning down a thermostat. Demand response generally involves a new kind of business service, *viz.*, an aggregator that automates demand-side flexibility for businesses and consumers and bids their aggregated reductions as a block into wholesale markets. *See* Joel Eisen, *supra*, at 81.

When reductions in demand are large enough or aggregated over a sufficient number of customers and can be deployed quickly, the total reduction becomes a significant resource for system operators to dispatch instead of more expensive generation to ensure just and reasonable rates. As respected economist Dr. Alfred Kahn explained, in these circumstances, "'[demand response] is in all essential respects economically equivalent to supply response'" and should "'be treated equivalently to generation in competitive power markets.'" Order 745 ¶ 20 (alteration in original) (quoting Kahn affidavit).

FERC began regulating demand response participation in organized wholesale electricity markets more than a decade ago. As early as May 2001, FERC found that "the current lack of meaningful demand side response is a flaw in the markets operated by PJM [the nation's largest RTO] which, if not corrected, could lead to dysfunction in those markets." *PJM Interconnection, LLC*, 95 FERC ¶ 61,306, at 62,043 (2001). *See also New England Power Pool ISO New England, Inc.*, 101 FERC ¶ 61,344, ¶ 46 (2002) ("measures that facilitate a robust demand response are essential to the success of competitive wholesale markets").[2]

After Congress enacted the EPAct in 2005 – with its declaration of U.S. policy "that ... unnecessary barriers to demand response participation in energy, capacity, and ancillary service markets shall be elim-

[2] *See also* Order 745 ¶ 13 n.27 (listing a number of tariffs from 2001 through 2010).

inated" – FERC accelerated its efforts. *See* Order 745 ¶ 11.

In 2007, in Order 890, FERC authorized non-generation resources, including demand response resources, to provide specified ancillary services related to transmission on comparable terms to those available to generation resources. *Preventing Undue Discrimination & Preference in Transmission Serv.*, Order 890, 118 FERC ¶ 61,119 (2007).

In 2008, FERC reaffirmed its policy "to identify and eliminate barriers to participation of demand response resources in organized power markets." *See* Order 719 ¶ 48. In Order 719, FERC implemented reforms to "remov[e] several barriers to the development and use of demand response resources in organized wholesale electric power markets." *Id.*

Specifically, FERC required RTOs and ISOs to "permit an aggregator of retail customers (ARC) to bid demand response on behalf of retail customers directly into the organized energy market," and to "accept bids from demand response resources in RTOs' and ISOs' markets for certain ancillary service on a basis comparable to other resources." *Id.* ¶¶ 3, 47, 154 (footnote omitted). These requirements would apply "unless the laws or regulations of the relevant electric retail regulatory authority do not permit a retail customer to participate." *Id.* ¶¶ 47, 154. FERC concluded that its order "properly balance[d] 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." *Id.* ¶ 156.

In its order on rehearing, Order 719-A, FERC responded to comments asserting that the Commission lacked jurisdiction. First, it noted the narrow focus of its rule: "It directs an RTO or ISO that operates an organized wholesale electric market – a market subject to the Commission's exclusive jurisdiction – to reduce certain barriers to demand response participation in that market." Order 719-A ¶ 48. FERC also explained that demand response has a direct effect on wholesale prices:

> The direct effect occurs when demand response is bid directly into the wholesale market: lower demand means a lower wholesale price. Demand response at the retail level affects the wholesale market indirectly because it reduces a load-serving entity's need to purchase power from the wholesale market. Demand response tends to flatten an area's load profile, which in turn may reduce the need to construct and use more costly resources during periods of high demand; the overall effect is to lower the average cost of producing energy. [*Id.* ¶ 47 (footnote omitted).]

As the preceding history shows, the orders under review here – Orders 745 and 745-A – are part of a lengthy process in which FERC has sought to comply with Congress's instruction to reduce barriers to demand response participation in electricity markets.

3. *Orders 745 and 745-A.* For years, FERC allowed each RTO and ISO to develop its own methods to determine compensation for demand response resources participating in wholesale markets, with the consequence that participation varied substantially and generally was underwhelming. Order 745 ¶ 14. In 2010, FERC expressed a concern that:

> [d]espite the benefits of demand response and various efforts by the Commission, ISOs and RTOs to address barriers to and compensation

> for demand response participation, demand response providers collectively play a small role in wholesale markets. After several years of observing demand response participation in ISO and RTO markets with different, and often evolving, demand response compensation structures, the Commission is concerned that some existing, inadequate compensation structures have hindered the development and use of demand response. [Demand Response Compensation in Organized Wholesale Energy Markets, 75 Fed. Reg. 15362, 15365, ¶ 9 (Mar. 29, 2010) (notice of proposed rulemaking).]

FERC decided to address this concern as it affected real-time and day-ahead wholesale energy markets, and issued a Notice of Proposed Rulemaking relating to the compensation of demand response resources in those markets. After considering 3,500 comments and holding a technical conference, FERC issued Order 745 and confirmed the findings made in its Notice. The Commission "recognized that barriers remain to demand response participation in organized wholesale energy markets." Order 745 ¶ 57. It specifically identified "the lack of market incentives to invest in enabling technologies that would allow electric customers and aggregators of retail customers to see and respond to changes in marginal costs of providing electric service as those costs change." *Id.*

To "address the[se] identified barriers to potential demand response providers," *id.* ¶ 58, FERC concluded that RTOs and ISOs should compensate demand response resources "at the market price for energy, referred to as the locational marginal price" if it assists in "balance[ing] supply and demand as an alternative to a generation resource" and if "dispatch of that demand response resource is cost-effective as determined by the net benefits test," *id.* ¶ 2. FERC ordered RTOs and ISOs to amend their tariffs to implement FERC's new requirements. *Id.* ¶¶ 6, 81; *see also* 18 C.F.R. § 35.28(b).

FERC found this approach to compensating demand response resources in wholesale energy markets "necessary to ensure that rates are just and reasonable in the organized wholesale energy markets." Order 745 ¶ 2. But, FERC did not require RTOs and ISOs to apply this requirement to bidders from states that prohibited demand response participation in RTO and ISO markets. *See* 18 C.F.R. § 35.28 (g)(1)(i)(A).

In responding to comments asserting that it lacked jurisdiction, FERC explained that FPA section 205 requires it to ensure that rates and charges for or "'in connection with'" the "sale for resale of electric energy in interstate commerce, and all rules and regulations 'affecting or pertaining to' such rates or charges are just and reasonable." Order 745 ¶ 112. Citing to its prior rulemakings, FERC observed that it had previously explained that demand response "directly affects" wholesale rates in wholesale electricity markets, giving it jurisdiction "to regulate the market rules under which an ISO or RTO accepts a demand response bid into a wholesale market." *Id.* ¶¶ 112-113 (citing Order 719-A ¶ 52).

FERC also asserted that its exercise of jurisdiction was supported by the Congressional policy statement in the EPAct, which encourages the removal of barriers to demand response participation in organized wholesale electricity markets.

Commissioner Moeller dissented. He did *not* argue that FERC lacks jurisdiction to regulate demand response resources' participation in wholesale electricity markets. Critically, he noted that "nowhere did I review any comment or hear any testimony that questioned the benefit of having demand response resources participate in the organized wholesale energy markets." Order 745, dissent at 1. He also agreed that "[s]ignificant barriers do exist which prevent demand response from reaching its full potential," and added that "demand response plays a very important role in these markets by providing significant economic, reliability and other market-related benefits." *Id.* at 2 n.5.

He believed, however, that paying demand response resources full LMP would overcompensate those resources because in addition to incentive payments received, those resources would not pay the cost of retail energy consumption that they otherwise would have incurred. *Id.* at 4-7.

On rehearing, FERC upheld its order, including its jurisdictional determination. FERC emphasized that "in the circumstances covered by the Final Rule, demand response resources are direct participants in the organized wholesale energy markets over which we have jurisdiction (just as is generation), and that participation has a direct and substantial effect on rates in those markets." Order 745-A ¶ 31. It also concluded that "[t]he fact that participation in a Commission-jurisdictional RTO or ISO market may indirectly affect incentives in a state demand response initiative does not deprive the Commission of the ability to act within [its "affecting" wholesale rates] jurisdictional boundaries." *Id.* ¶ 32. Finally, FERC emphasized that it had preserved state flexibility with respect to demand response by creating an exception to its requirement that RTOs and ISOs accept bids from demand response resources when such participation is "not permitted by the laws or regulations of the relevant electric retail regulatory authority." 18 C.F.R. § 35.28(g)(1)(i)(A), (iii).

4. *The Court of Appeals' Decision.* On May 23, 2014, a divided panel of the D.C. Circuit held that the FPA does not provide FERC with jurisdiction to issue Order 745. The panel majority "agree[d] with [FERC] that demand response compensation affects the wholesale market," observing that it will both "lower the wholesale price" and "increase system reliability." App. 7a. *See id.* at 13a (explaining that petitioners "do not dispute" "the importance of demand response resources to the wholesale market"). But, the court nonetheless rejected FERC's argument that it was properly exercising its jurisdiction over matters "affecting" wholesale rates and sales on two grounds.

First, the court expressed concern that FERC's "affecting" jurisdiction "has no limiting principle" and "could ostensibly authorize FERC to regulate any number of areas, including steel, fuel and labor markets." App. 7a. The court acknowledged FERC's position that its jurisdiction should extend to "'direct participants' in jurisdictional wholesale energy markets," but rejected it, saying that FERC had "'lure[d]' non-jurisdictional resources into the wholesale market in the first place to create jurisdiction." *Id.* at 7a-8a.

Second, the court said, "FERC can regulate practices affecting the wholesale market ... provided the Commission is not directly regulating a matter subject to state control, such as the retail market." App. 9a. And, the panel concluded, demand response is "part of the retail market. It involves *retail* customers, their decision whether to purchase *at retail*, and the levels of *retail* electricity consumption." *Id.* at 10a.

The court also noted that the EPAct is a statement of Congressional policy rather than an independent source of authority. It read the Act to limit FERC's role "to assist[ing] and advis[ing] state and regional programs." App. 13a.

Finally, the court held that FERC's decision to set compensation for demand response resources at LMP was arbitrary and capricious because FERC failed adequately to explain its reasoning and to address arguments that LMP pricing would overcompensate demand response resources. App. 14a-15a.

Judge Edwards dissented. He explained that the jurisdictional line between FERC's wholesale jurisdiction and the states' retail jurisdiction "is neither neat nor tidy," App. 16a, and that FERC is entitled to deference in determinations about the scope of its jurisdiction. *Id.* at 18a-20a. He concluded that "there is no doubt that demand response participation in wholesale markets and the ISOs' and RTOs' market rules concerning such participation constitute 'practice[s] ... affecting' wholesale rates"; and therefore that it was "reasonable for the Commission to conclude that it could issue Order 745 under the Act's 'affecting' jurisdiction" provision. *Id.* at 20a.

Judge Edwards observed that FERC had initiated a "series of reforms to open wholesale markets to 'demand response resources,'' App. 24a, and that "[f]or some years now, FERC has recognized that the direct participation of demand response resources in wholesale markets improves the functioning of these markets in several respects." *Id.* at 25a. Specifically, FERC has explained that doing so (i) "lowers wholesale prices because lower demand means a lower wholesale price"; (ii) "mitigates market power of suppliers of electricity because they have to compete with demand response resources and adjust their bidding strategy accordingly"; and (iii) "enhances system reliability, for example, by reducing electricity demand at critical times." *Id.* (internal quotations omitted).

Further, he pointed out that Order 745 does not intrude on state authority over retail sales and markets both because demand response is not a retail sale, and because the Order calls for compensation of demand response resources only when state law permits such resources to participate in organized wholesale markets. App. 31a ("[T]he Order preserves State regulation of retail markets. This is hardly the stuff of grand agency overreach."). He also rejected the notion that there is no limiting principle to FERC's jurisdictional authority to regulate demand response under sections 205 and 206 – explaining that FERC cannot directly regulate retail sales and FERC can regulate only matters that directly affect or are closely related to wholesale rates. *Id.* at 33a-34a.

Finally, the dissent asserted that the court should have deferred to FERC concerning the proper compensation scheme for demand response in the wholesale market, because the Commission provided a reasonable explanation for compensating demand response resources at LMP. App. 39a-44a.

FERC and numerous other parties (including State Public Service Commissions) filed petitions seeking rehearing en banc solely on the jurisdictional issue. No state filed in support of the court's decision. In addition, several state regulatory authorities and consumer advocate groups offered statements of support for FERC's petition. The court denied all petitions.

Thereafter FERC and other parties requested that the mandate be stayed. The court of appeals granted

FERC's motion; it stayed issuance of the mandate until December 16, 2014 and then extended that stay to January 15, 2015. App. 256a-259a. The court also stated that if a petition for certiorari is filed by the latter date, the stay continues in effect until this Court acts on the petition. *Id.* at 257a.

REASONS FOR GRANTING THE PETITION

I. THE COURT OF APPEALS HAS INCORRECTLY DECIDED A CRITICALLY IMPORTANT QUESTION ABOUT THE SCOPE OF FERC'S JURISDICTION.

This case concerns the fundamental question of the scope of FERC's authority to regulate organized wholesale energy markets. Those multi-state markets are operated by FERC-approved entities, RTOs and ISOs, under tariffs approved by FERC. The markets determine wholesale prices of energy for their regions, a matter within FERC's exclusive jurisdiction. And Order 745 addresses *only* the terms under which RTOs and ISOs are authorized to allow demand response resources to participate in those wholesale markets. It does not regulate retail markets or rates; indeed, the Order specifically states that it applies only to the extent that demand response resources' participation in regional wholesale energy markets is permitted under state law. Order 745 ¶ 114; *see also* Order 745-A ¶¶ 11, 32; Order 719 ¶¶ 47, 154.

There is no gainsaying the importance of demand response participation in wholesale energy markets and the benefits that participation provides. Congress has declared a national policy to encourage it. FERC Commissioner Moeller – who disagreed with the method FERC adopted to compensate demand response resources in wholesale energy markets[3] – did not doubt FERC's jurisdiction. He explained that "there is no debate" about the benefits of demand response participation "in the organized wholesale energy markets," or its "very important role in [those] markets." Order 745, dissent at 1.

The D.C. Circuit's crabbed interpretation of FERC's jurisdiction threatens FERC's successful, decade-long effort to encourage demand participation in organized wholesale markets, with damaging, costly consequences for those markets and consumers, for states and for the nation, and for energy innovation and technological advances.

None of these consequences is necessary because the D.C. Circuit's reading of the FPA's text is wrong and contrary to this Court's cases.

A. The D.C. Circuit's Reading Cannot Be Reconciled With The FPA's Text.

Section 201(b) of the FPA gives FERC jurisdiction over "the transmission of electric energy in interstate commerce" and "the sale of electric energy at wholesale in interstate commerce." 16 U.S.C. § 824(b). FERC's jurisdiction is "exclusive," and "extend[s] to" ensuring that "rates and practices ... affecting rates, are just and reasonable." *Nw. Cent. Pipeline Corp. v. State Corp. Comm'n*, 489 U.S. 493, 506 (1989).[4]

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[3] Petitioners do not separately seek review of this aspect of the court of appeals' decision unless this Court would consider review of that issue helpful or necessary to its review of the jurisdictional question.

[4] The relevant provisions of the Natural Gas Act ("NGA") and the FPA "'are in all material respects substantially identical,'"

Thus, FERC has authority to regulate "any rule, regulation, practice or contract affecting [a] rate" subject to the jurisdiction of the Commission. 16 U.S.C. § 824e(a). That text broadly grants FERC regulatory power over the practices "'affecting'" wholesale rates "without qualification or exception." *Permian Basin Area Rate Cases*, 390 U.S. 747, 783-84 (1968). This Court has further explained that "[t]he rules, practices, or contracts 'affecting' the jurisdictional rate are not themselves limited to the jurisdictional context." *Fed. Power Comm'n v. Conway Corp.*, 426 U.S. 271, 281 (1976). *See also Miss. Power & Light Co. v. Miss. ex rel. Moore*, 487 U.S. 354, 371 (1988) (FERC's exclusive jurisdiction "applies not only to rates but also to [practices] that affect wholesale rates").

That is not to say that FERC has authority over state practices with only tangential effects on wholesale rates. The effect on wholesale rates must be direct. *See Nw. Cent. Pipeline*, 489 U.S. at 514, 517-19; *Schneidewind v. ANR Pipeline Co.*, 485 U.S. 293, 308 (1988). In addition, FERC cannot directly regulate matters expressly assigned to states by section 201(b) of the FPA, such as retail sales and intra-state transmission and generating facilities. *See* 16 U.S.C. § 824(b)(1).[5]

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and this Court follows an "established practice of citing interchangeably decisions interpreting the pertinent sections of the two statutes." *Ark. La. Gas Co. v. Hall*, 453 U.S. 571, 577 n.7 (1981).

[5] Section 201(b) of the FPA provides FERC with jurisdiction over wholesale sales and interstate transmission, and then states that FERC cannot regulate "any other sale of electric energy" or "facilities used for the generation of electric energy or over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce, or over facilities

The majority below agreed that regulation of RTOs' and ISOs' treatment of demand response resources affects wholesale rates. But it nonetheless concluded that FERC lacks jurisdiction on the ground that Order 745 impinges on an area of exclusive state control established by FPA section 201(b).

The court's decision cannot be reconciled with the text of section 201(b). Order 745 does not regulate electric generation, the local distribution of electricity or retail sales of electricity. The panel recognized that demand response is not itself a *sale* of electricity; *a fortiori*, it cannot be a retail sale over which the states have exclusive authority. App. 6a. In responding to an argument that the NGA's analogous provision (section 1(b)) "create[d] a complete exemption of direct sales from [federal] curtailment regulations," this Court explained: "The answer is that ... §1(b) withheld from [FERC] only *rate-setting* authority with respect to direct sales." *Fed. Power Comm'n v. La. Power & Light Co.*, 406 U.S. 621, 637-38 (1972). Order 745 does not *set* retail rates. *See also* App. 31a (dissenting opinion) ("[t]he demand response at issue here is forgone consumption, which is no 'sale' at all," and thus not within state authority under FPA section 201(b)).

Significantly, moreover, the FPA is not symmetrical: FERC has jurisdiction over matters directly "affecting" wholesale rates. States have carefully delineated jurisdiction, including over rates for retail sales of energy, but do not have analogous "affecting" jurisdiction over any matter related to rates for retail sales. The states' jurisdiction over rates for retail

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for the transmission of electric energy consumed wholly by the transmitter." 16 U.S.C. § 824(b)(1).

sales of electric energy cannot be expanded to embrace all matters "affecting" retail rates, and certainly not to displace a FERC Order directed at jurisdictional entities such as RTOs and ISOs, that regulates their management of markets for wholesale energy and that preserves existing state programs involving demand response, *see supra* p. 15.

Under the plain meaning of the FPA's text, FERC has jurisdiction to regulate regional wholesale electricity markets and the participation of demand response resources in those markets. And FERC's repeated invocations of the importance of demand response participation in wholesale markets and its established practice of regulating such participation simply underscore this point. *See supra* pp. 11-17. The D.C. Circuit should have "accord[ed] particular deference to [this] agency interpretation of 'longstanding' duration." *Barnhart v. Walton*, 535 U.S. 212, 219-20 (2002).

The court below also expressed concern that FERC's argument – that it has jurisdiction over matters directly affecting wholesale energy rates – "has no limiting principle" and would allow FERC "to regulate any number of areas, including the steel, fuel and labor markets." App. 7a. But steel, fuel and labor are merely inputs for the construction and operation of electricity generation and thus only indirectly influence bids in wholesale markets, while demand response resources participate in wholesale markets and directly affect wholesale rates. Put differently, one obvious limiting principle here is that FERC is regulating only the wholesale tariffs filed by jurisdictional entities operating in jurisdictional markets. In any event, this Court has long applied the direct effects test in addressing the scope of FERC's jurisdiction under the FPA and the NGA, *see infra* pp. 26-28.

It and other courts have had no difficulty distinguishing direct from attenuated effects. *See La. Power & Light*, 406 U.S. at 637-38 (rejecting a similar argument that construing the NGA to withhold from federal regulation "only *rate-setting* authority with respect to direct sales" would "swallow up the proviso's exemption for direct sales").

Finally, at the very least, the FPA is ambiguous about whether FERC's Order invades matters within the states' jurisdiction. Thus, the court should have deferred to FERC's judgment about the imperatives of demand response participation in regional wholesale electricity markets and its established practice of regulating that participation. *See City of Arlington v. FCC*, 133 S. Ct. 1863, 1868, 1874-75 (2013) (courts are obliged to give *Chevron* deference to an agency's construction of "a statutory ambiguity that concerns the scope of the agency's statutory authority (that is, its jurisdiction)").

B. The D.C. Circuit's Decision Cannot Be Reconciled With This Court's Cases And Is Also Inconsistent With Decisions From Other Courts Of Appeals.

This Court has recognized the importance of interstate electricity and natural gas markets and has frequently granted review to address the scope of FERC's jurisdiction under the FPA and the NGA. The panel's decision "conflicts with relevant decisions of this Court," delineating FERC's jurisdiction. *See* Sup. Ct. R. 10(c).

This Court's decision in *Mississippi Power* demonstrates that the D.C. Circuit's decision is wrong. That case involved an agreement among four power companies allocating power produced by a nuclear plant. The Court held that the agreement was a "contract affecting the wholesale rates of those ... companies," 487 U.S. at 360 n.6, and that "States may not regulate in areas where FERC has properly exercised its jurisdiction to ... insure that agreements affecting wholesale rates are reasonable." *Id.* at 374. Thus, Mississippi could not regulate that contract's power allocations even though it sought to do so in the "exercise of its undoubted jurisdiction over retail sales," specifically over the prudence of "an increase in [the power company's] retail rates." *Id.* at 365, 372; *see also id.* at 374, 376.

This Court did not find that the FPA displaces FERC's jurisdiction over a matter "affecting" wholesale rates whenever a state seeks to regulate the retail power market. Instead, the Court examined the impact of state action on wholesale rates and concluded that it impermissibly "affected" rates within FERC's jurisdiction and was preempted, even though the State was regulating retail markets.

Here, the terms of demand response participation in organized wholesale markets directly and substantially affect wholesale rates. And, the panel did *not* find that FERC was regulating retail *rates*. That should have been the end of the matter. Instead, and contrary to this Court's approach, the D.C. Circuit panel *displaced* FERC jurisdiction over RTOs and ISOs and their operation of organized wholesale markets on the theory that FERC's action might have an indirect impact on state regulation of retail markets. This analysis is plainly inconsistent with the approach this Court takes in *Mississippi Power*.

Northern Natural Gas Co. v. State Corp. Commission, 372 U.S. 84 (1983), also illustrates this point in the analogous context of NGA jurisdiction. There, Kansas argued that it could require interstate pipelines to purchase gas from state producers in proportion to the latter's production, on the theory that it was regulating only "the 'production or gathering' of natural gas, which is exempted from" federal regulation under the NGA. *See id.* at 89. Kansas further argued that its regulation was directed at conservation of natural gas, "traditionally a function of state power." *Id.* at 93. This Court rejected the State's arguments, concluding that FERC had exclusive authority to regulate "the intricate relationship between the purchasers' cost structures and eventual costs to wholesale customers," *id.* at 92, even though the nominal subject of the state law involved matters within state authority.

To be sure, FERC cannot directly regulate rates of retail sales of energy. But much FERC regulation has an *effect* on retail matters, and nothing in this Court's analysis in cases arising under the FPA and the NGA suggests that FERC's authority to regulate the operations of regional markets and practices "affecting" wholesale rates in those markets is eliminated when a state is regulating a matter *related to* the retail market. Thus, here, it does not matter that FERC's regulation of demand response resources participation in wholesale markets run by RTOs and ISOs might somehow affect the retail market. That fact does not divest FERC of jurisdiction. *See also Nantahala Power & Light Co. v. Thornburg*, 476 U.S. 953, 966 (1986) (state authority is limited to "'those [sales] which Congress has made explicitly subject to regulation by the States'"); *La. Power & Light Co.*, 406 U.S. at 623, 637-38, 642 (the statute "withheld from [FERC] only rate-setting authority with respect to direct sales," and thus FERC has authority to require pipelines to restrict retail and wholesale gas deliveries in times of gas shortage).

Because the D.C. Circuit's approach to FERC's "affecting" jurisdiction conflicts with this Court's precedent, it is not surprising that it is also contrary to the approach taken by the courts of appeals, including in two recent decisions. *See PPL EnergyPlus, LLC v. Nazarian*, 753 F.3d 467 (4th Cir. 2014); *PPL EnergyPlus, LLC v. Solomon*, 766 F.3d 241 (3d Cir. 2014). Those cases involved, respectively, Maryland and New Jersey laws intended to promote the creation of new generation capacity in those States. Both courts of appeals invalidated the state laws based on FERC's authority to regulate wholesale rates and practices directly affecting wholesale rates, holding that the state laws – nominally directed at a matter the FPA assigns to the states (generating capacity) – would have a direct effect on wholesale rates. *Compare In re W. States Wholesale Natural Gas Antitrust Litig.*, 715 F.3d 716 (9th Cir. 2013) (giving FERC's "affecting" jurisdiction under the NGA an unduly narrow reading), *cert. granted*, *ONEOK, Inc. v. Learjet, Inc.*, 134 S. Ct. 2899 (2014). *See infra* pp. 33-34.

This Court should grant certiorari to review the D.C. Circuit's decision and reestablish the proper scope of FERC's jurisdiction under the FPA.

II. THE DECISION WILL INJURE ELECTRIC MARKETS, CONSUMERS, AND STATES AND IMPEDE TECHNOLOGICAL INNOVATION.

If the decision below stands, it will undermine FERC's decade-long effort to act in accord with Congress's determination that unnecessary barriers to demand response participation in energy, capacity and ancillary services markets should be eliminated. EPAct, Pub. L. No. 109-58, § 1215(f), 119 Stat. at 966.

The real world consequences of this decision for wholesale markets are dramatic. FERC has concluded that the wholesale energy market "functions effectively *only* when both supply and demand can meaningfully participate," Order 745 ¶¶ 1, 57 (emphasis added). Demand response now plays an important role in wholesale energy markets, reducing prices and unnecessary generation and increasing system reliability. Order 745-A ¶¶ 23-24; Order 745 ¶¶ 112-115. Indeed, FERC found exercising jurisdiction over demand response "essential to the Commission fulfilling its statutory responsibility to ensure that jurisdictional rates are just and reasonable." Order 745-A ¶ 20. Unless the D.C. Circuit's decision is vacated, wholesale energy markets will not "function[] effectively": Competition will be constrained; prices will be higher; service will be less reliable.

Moreover, the decision is placing a cloud over the operation of other markets regulated by FERC. It has already resulted in crippling uncertainty in capacity markets. For the last ten years, with FERC approval, grid operators have allowed demand response resources to compete to satisfy forward-looking capacity needs. RTOs and ISOs now count on those resources in planning to meet their capacity needs in years to come, and to limit the expensive, unnecessary building of generation resources. For example, PJM has held auctions for its forward capacity markets for 2015 through 2017, and secured demand response commitments for over 10,000 megawatts for each of those seasons. PJM Pet. For Reh'g 9. *See also* Monitoring Analytics, *Analysis of the 2017/2018 RPM Base Residual Auction* 6 (2014), *available at* http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Analysis_of_the_2017_2018_RPM_Base_Residual_Auction_20141006.pdf

(PJM's independent market monitor estimated that removing demand response resources from PJM's capacity auction would cost customers approximately nine billion dollars in the 2017/2018 delivery year).

Demand response participation in capacity markets is also critical for the reliability of the electric grid. Again, PJM's experience offers helpful illustrations. In the 2013 summer and in the "polar vortex" of the 2014 winter, PJM deployed demand response to maintain system reliability and to meet its highest ever winter peak demand. *See* Maryland & California Pet. For Reh'g 12-13 & nn.16-18. Indeed, in the 2013 summer, in response to system emergencies and weather events, PJM and grid operators in New York and New England deployed emergency demand response for 13 days to avoid blackouts. FERC Pet. For Reh'g 14-15 & nn.7-8; *see also* FERC, *Assessment of Demand Response and Advanced Metering* 12-13 (2013); William Massey, Robert Fleishman & Mary Doyle, *Reliability-Based Competition in Wholesale Electricity: Legal and Policy Perspectives*, 25 Energy L.J. 319, 350-52 (2004) (describing NARUC and GAO studies identifying "the considerable reliability potential of demand response").

But the D.C. Circuit's opinion is already being used as a tool to attempt to eliminate demand response from capacity markets. On the day the panel released its decision, FirstEnergy Service Co. filed an emergency complaint with FERC, challenging FERC's authority to regulate the participation of demand response resources in PJM's capacity market and requesting that FERC order PJM to remove all portions of its tariff allowing or requiring PJM to include demand response as suppliers in its capacity market. *See* Complaint, *FirstEnergy Serv. Co. v. PJM Interconnection, LLC*, FERC Docket No. EL14-55-000 (filed May 23, 2014) (seeking to extend panel's reasoning to capacity markets). It was followed by a similar complaint with respect to the market administered by New England's ISO. *See* Complaint, *New England Power Generators Assoc. v. ISO New England, Inc.*, FERC Docket No. EL15-21-00 (filed Nov. 14, 2014) (same).

Given the federalism undercurrent in the panel opinion, it is ironic that demand response participation in wholesale markets is strongly supported by states. A number of them filed petitions for, or supported, rehearing in this case, arguing that "[p]ermitting [demand response] resources to be compensated in FERC jurisdictional wholesale markets to enable them to participate in those markets is in the state's and public's interest." Maryland & California Pet. For Reh'g 5; *id.* at 1 n.1 (citing support from the Delaware Public Service Commission, the New York Public Service Commission, and the New England Conference of Public Utilities Commissioners); Pennsylvania Pet. For Reh'g.

States support demand response participation in wholesale markets for numerous reasons. First, demand response saves consumers money because reduced wholesale prices translate into lower retail prices for electricity. Moreover, demand response also provides a substantial benefit to those customers who receive demand response payments in exchange for the service they provide in wholesale markets. Demand response payments resulting from the efficiency gains in wholesale markets place hundreds of millions of dollars in the hands of American businesses, state governments, schools, hospitals and countless municipalities. *See* James McAnany, *2013 Demand Response Operations Markets Activity Report* 9 fig.10 (2013), *available at* http://www.pjm.com/~/

media/markets-ops/dsr/2013-dsr-activity-report-20131210.ashx (reporting over $400 million paid to demand response participants).

Second, states support demand response because it increases system reliability, as detailed above. *See supra* p. 29. "[D]emand response repeatedly has proven its value – especially at times when the system is in emergency conditions or otherwise stressed." PJM Mot. for Reh'g 4.

Third, "States depend on the value of [demand response] being applied in wholesale markets to meet a variety of legislatively targeted electricity reduction goals," Maryland & California Pet. For Reh'g 8, generally directed at preventing environmental harm. Demand response can decrease the need to construct new power plants, Order 719 ¶ 203, and prevent the running of older, less efficient power plants during peak demand periods, Order 745 ¶ 33. Demand response service "reduces harmful air pollution by avoiding the dispatch of inefficient, high-emitting generation during times of peak electricity demand." Br. Of Amici Curiae Environmental Defense Fund *et al.* 7 (filed July 8, 2014).

Finally, FERC's efforts to remove barriers to participation of demand response in electricity markets include regulation to "encourage[e] development and implementation of new technologies" to support that participation. Order 719 ¶ 48. *See* EPAct, Pub. L. No. 109-58, § 1215(f), 119 Stat. at 966 ("the deployment of such technology and devices that enable electricity customers to participate in such pricing and demand response systems shall be facilitated"). Financial incentives encourage the development of technologies that allow more efficient use of energy. In reliance on FERC's actions over the past decade, private companies and the federal government have invested billions of dollars to develop and deploy technologies necessary to enable a smart electric power grid. *See*, *e.g.*, U.S. Dep't of Energy, *Smart Grid Investment Grant Program: Progress Report II* (2013), *available at* http://energy.gov/sites/prod/files/2013/10/f3/SGIG_progress_report_2013.pdf. Ending wholesale energy market participation for demand response providers (and causing uncertainty about its participation in capacity and ancillary services markets) would deprive demand resource providers of revenues and incentives supporting the development of new technologies and the expansion of service to new customers. *See*, *e.g.*, Maryland & California Pet. For Reh'g 10-11.

In sum, the court of appeals' decision will prevent FERC from effectively regulating competition in wholesale energy markets and ensuring just and reasonable rates, to the detriment of consumers, states, and technological advances in energy management. It warrants this Court's review.

III. IN THE ALTERNATIVE, THE PETITION SHOULD BE HELD PENDING RESOLUTION OF *ONEOK v. LEARJET*.

As set forth above, this case concerns FERC's authority to regulate wholesale rates and practices that directly affect jurisdictional rates, and specifically when FERC's authority must give way to state regulation. This Court recently granted a petition to address a similar issue, arising from the parallel jurisdictional grant to FERC in the NGA. *See ONEOK, Inc. v. Learjet, Inc.*, 134 S. Ct. 2899 (2014) (granting certiorari).

In the decision under review in *ONEOK*, the Ninth Circuit, like the D.C. Circuit here, announced a narrow reading of FERC's authority to regulate "any ...

practices ... affecting" jurisdictional rates, citing the statutory provision that excludes retail sales from FERC's authority. *In re W. States Wholesale Natural Gas Antitrust Litig.*, 715 F.3d 716 (9th Cir. 2013). The Ninth Circuit emphasized that the plaintiffs bought gas at retail and that FERC has no jurisdiction over retail sales. It held that state law is not preempted when a plaintiff's claim is "associated with" non-jurisdictional transactions. *Id.* at 730-34. Like the D.C. Circuit here, the Ninth Circuit believed that any other reading would lack a "'conceptual core' delineating transactions falling within FERC's jurisdiction and transactions outside of FERC's jurisdiction." *Id.* at 733. The Ninth Circuit's approach is contrary to the NGA's text and this Court's cases.

As noted above, the NGA and the FPA establish parallel regulatory schemes. This Court's existing precedent mandates reversal of the decision below. But, if the Court chooses not to grant the petition immediately, it should nonetheless hold the petition until it decides the scope of FERC"s jurisdiction over practices "affecting" wholesale rates in *ONEOK*.

CONCLUSION

For the foregoing reasons, this Court should grant the petition.

Respectfully submitted,

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January 15, 2015

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APPENDIX

APPENDIX A

United States Court of Appeals,
District of Columbia Circuit.

Nos. 11–1486, 11–1489, 12–1088, 12–1091, 12–1093.

ELECTRIC POWER SUPPLY ASSOCIATION,
Petitioner

v.

FEDERAL ENERGY REGULATORY COMMISSION,
Respondent.
MADISON GAS AND ELECTRIC COMPANY, *et al*.,
Intervenors.

Argued Sept. 23, 2013. | Decided May 23, 2014.

Opinion

Before: BROWN, *Circuit Judge*, and EDWARDS and SILBERMAN, *Senior Circuit Judges*.

Opinion for the Court by Circuit Judge BROWN.

Dissenting opinion filed by Senior Circuit Judge EDWARDS.

BROWN, Circuit Judge:

Electric Power Supply Association and four other energy industry associations ("Petitioners") petition this court for review of a final rule by the Federal Energy Regulatory Commission ("FERC" or "the Commission") governing what FERC calls "demand response resources in the wholesale energy market." The rule seeks to incentivize retail customers to reduce electricity consumption when economically efficient. Petitioners complain FERC's new rule goes too far, encroaching on the states' exclusive jurisdiction to regulate the retail market. We agree and vacate the rule in its entirety.

I

Under the Federal Power Act ("FPA" or "the Act") the Commission is generally charged with regulating the transmission and sale of electric power in interstate commerce. The FPA "split[s] [jurisdiction over the sale and delivery of electricity] between the federal government and the states on the basis of the type of service being provided and the nature of the energy sale." *Niagara Mohawk Power Corp. v. FERC*, 452 F.3d 822, 824 (D.C.Cir.2006). Section 201 of the Act empowers FERC to regulate "the sale of electric energy *at wholesale* in interstate commerce." 16 U.S.C. § 824(b)(1) (emphasis added). Thus, "FERC's jurisdiction over the sale of electricity has been specifically confined to the wholesale market." *New York v. FERC*, 535 U.S. 1, 19, 122 S.Ct. 1012, 152 L.Ed.2d 47 (2002).

The Commission concedes that "demand response is a complex matter that lies at the confluence of state and federal jurisdiction." See Demand Response Compensation in Organized Wholesale Energy Markets, 134 FERC ¶ 61,187, 2011 WL 890975, at *30 (Mar. 15, 2011) [hereinafter Order 745]. For more than a decade, FERC has permitted demand-side resources to participate in organized wholesale markets, allowing Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs) to use demand-side resources to meet their systems' needs for wholesale energy, capacity, and ancillary services. As this court has noted, Congress in 2005 declared "the policy of the United States that time-based pricing and other forms of demand response . . . shall be encouraged . . . and unnecessary barriers to demand response participation in energy, capacity and ancillary service markets shall be eliminated." *Ind. Util. Reg. Comm'n v. FERC*, 668 F.3d 735, 736 (D.C.Cir.2012) (citing 16 U.S.C. § 2642). The Commission has issued dozens of orders on demand-side resource participation, and ISOs and RTOs maintaining economic demand response programs could file tariffs with the Commission and accept bids for ancillary services and from aggregators of retail customers directly into the wholesale energy markets. *See* Wholesale Competition in Regions with Organized Electric Markets, 73 Fed.Reg. ¶ 64,100, 64,101 (Oct. 28, 2008) (to be codified at 18 C.F.R. pt. 35) [Order 719].

Order 745 establishes uniform compensation levels for suppliers of demand response resources who participate in the "day-ahead and real-time energy markets." Order 745, 2011 WL 890975, at *1. The order directs ISOs and RTOs to pay those suppliers, including aggregators of retail customers, the full locational marginal price (LMP), or the marginal value of resources in each market typically used to compensate generators. The Commission conditioned the payment of full LMP on the ability of a demand response resource to replace a generation resource and required demand response to be cost effective. Cost effectiveness would be determined by a newly devised "net benefits test," which FERC directed ISOs and RTOs to implement. FERC acknowledged that the cost of payments to retail customers to encourage reduced energy consumption would have to be subsidized by load-serving entities participating in the wholesale market. *Id*. ¶ 99, 2011 WL 890975, at *27; *see also id*. ¶ 102. Finally, the rule allocated the costs of demand response payments proportionally to all entities that purchase from the relevant energy markets during times when demand response resources enter the market. Commissioner Moeller dissented, arguing the Commission's retail customer compensation scheme conflicted both with FERC's efforts to promote competitive markets and with its statutory mandate to ensure supplies of electric energy at just, reasonable, and not unduly preferential or discriminatory rates. *See id*., 2011 WL 890975, at *34–39.

Requests for rehearing and clarification were filed by ISOs, RTOs, state regulatory commissions, trade associations, publicly owned utilities, transmission owners, suppliers, and others. The Commission, in another 2–1 decision, confirmed its approach and Petitioners filed timely petitions for review.

II

The Administrative Procedure Act (APA) directs us to "hold unlawful and set aside agency action . . . in excess of statutory jurisdiction, authority, or limitations." 5 U.S.C. § 706(2)(C). "FERC is a creature of statute" and thus "has no power to act unless and until Congress confers power upon it." *Cal. Indep. Sys. Operator Corp. (CAISO) v. FERC*, 372 F.3d 395, 398 (D.C.Cir.2004) (citing *La. Pub. Serv. Comm'n v. FCC*, 476 U.S. 355, 374, 106 S.Ct. 1890, 90 L.Ed.2d 369 (1986)). If FERC lacks authority under the Federal Power Act to promulgate a rule, its action is "plainly contrary to law and cannot stand." *See Michigan v. EPA*, 268 F.3d 1075, 1081 (D.C.Cir.2001).

We address FERC's assertion of its statutory authority under the familiar *Chevron* doctrine. *See City of Arlington, Tex. v. FCC*, ––U.S. ––, 133 S.Ct. 1863, 1870–71, –– L.Ed.2d –– (2013). The question is "whether the statutory text forecloses the agency's assertion of authority." *Id*. at 1871. If, however, the statute is silent or ambiguous on the specific issue, we must defer to the agency's reasonable construction of the statute. *Id*. at 1868.

FERC claims when retail consumers voluntarily participate in the wholesale market, they fall within the Commission's exclusive jurisdiction to make rules for that market. Petitioners protest that retail sales of electricity are within the traditional and "exclusive jurisdiction of the States" and regulating consumption by retail electricity customers is a regulation of retail, not wholesale, activity. Reply Br. 11–12. The problem, Petitioners say, is the Commission has no authority to draw retail customers into the wholesale markets by paying them not to make retail purchases.

Initially, we note the regulations have a single definition of "demand response"—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." 18 C.F.R. § 35.28(b)(4) (emphasis added); *see also* Order 745, 2011 WL 890975, at *1 n. 2. High retail rates will reduce demand. Conversely, if consumers are paid to reduce demand, prices fall. FERC acknowledges the first case, "price-responsive demand" is a "retail-level" demand response. *See* Order 745, 2011 WL 890975, at *1–3 & n. 2 (citing 18 C.F.R. § 35.28(b)(4)). In contrast, FERC dubs a reduction in the consumption of energy in response to incentive payments a "wholesale demand response." *See* FERC Br. 5, 34; *see also* Order 745, 2011 WL 890975, at *1–3 & n. 2 (citing 18 C.F.R. § 35.28(b)(4)). The Commission draws this distinction between "wholesale demand response" and "retail demand response" in an attempt to narrow the logical reach of its rule. *See*, *e.g.*, FERC Br. 5 ("[T]he Commission has made plain that its focus is narrow and that it addresses only wholesale demand response."); *id*. ("States remain free to authorize and oversee retail demand response programs."); *id*. at 14–15. Yet FERC acknowledges "*wholesale* demand response" is a fiction of its own construction. See Oral Arg. Tape, No. 11–1486, at 27:31 (Sept. 23, 2013) (conceding "selling" demand response resources in the wholesale market "is a bit of a fiction"). Demand response resources do not *actually* sell into the market. Demand response does not involve a sale, and the resources "participate" only by declining to act.

As noted, and as the Commission concedes, demand response is not a wholesale sale of electricity; in fact, it is not a sale at all. *See* Order 745, 2011 WL 890975, at *18 ("[T]he Commission does not view demand response as a resale of energy back into the energy market."). Thus, FERC astutely does not rely exclusively on its wholesale jurisdiction under § 201(b)(1) for authority. *See Niagara Mohawk Power Corp*., 452 F.3d at 828 & n. 7.

Instead, FERC argues §§ 205 and 206 grant the agency authority over demand response resources in the wholesale market. These provisions task FERC with ensuring "all rules and regulations *affecting* . . . rates" in connection with the wholesale sale of electric energy are "just and reasonable." 16 U.S.C. § 824d(a) (emphasis added); *see also id*. § 824e(a). Thus, the

Commission argues it has jurisdiction over demand response because it "directly affects wholesale rates." FERC Br. 32–34; *see also* Order 745, 2011 WL 890975, at *30.

We agree with the Commission that demand response compensation affects the wholesale market. Because of the direct link between wholesale and retail markets, *compare* FERC Br. 32, *with* Pet'rs Br. 11–14 (describing the "direct" relationship between wholesale and retail rates), and Reply Br. 12 ("[T]here is undeniably a link between wholesale rates and retail sales"), a change in one market will inevitably beget a change in the other. Reducing retail consumption—through demand response payments—will lower the wholesale price. *See* Oral Arg. Tape, at 33:13. Demand response will also increase system reliability. FERC Br. 33. Because incentive-driven demand response affects the wholesale market in these ways, the Commission argues §§ 205 and 206 are clear grants of agency power to promulgate Order 745.

The Commission's rationale, however, has no limiting principle. Without boundaries, §§ 205 and 206 could ostensibly authorize FERC to regulate any number of areas, including the steel, fuel, and labor markets. FERC proposes the "affecting" jurisdiction can be appropriately limited to "direct participants" in jurisdictional wholesale energy markets. *See* FERC Br. 37. But, as this case demonstrates, the directness of participation may be a function of the richness of the incentives FERC commands. The commission's authority must be cabined by something sturdier than creative characterizations. *See Altamont Gas Transmission Co. v. FERC*, 92 F.3d 1239, 1248 (D.C.Cir.1996) (noting FERC cannot "do indirectly what it could not do directly"). The "direct participant" theory also assumes FERC can "lure" non-jurisdictional resources into the wholesale market in the first place to create jurisdiction, *see* Oral Arg. Tape, at 29:52, which is the heart of the Petitioners' challenge.

The limits of §§ 205 and 206 are best determined in the context of the overall statutory scheme. *See FDA v. Brown & Williamson Tobacco Corp*., 529 U.S. 120, 132–33, 120 S.Ct. 1291, 146 L.Ed.2d 121 (2000). Congressional intent is clearly articulated in § 201's text: FERC's reach "extend[s] only to those matters which are not subject to regulation by the States." 16 U.S.C. § 824(a). States retain exclusive authority to regulate the retail market. *See Niagara Mohawk Power Corp*., 452 F.3d at 824. Absent a "clear and specific grant of jurisdiction" elsewhere, *see New York*, 535 U.S. at 22, 122 S.Ct. 1012, the agency cannot regulate areas left to the states. The broad "affecting" language of §§ 205 and 206 does not erase the specific limits of § 201.[1] *See generally RadLAX Gateway Hotel,*

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[1] The Dissent focuses extensively on § 201(b)(1), positing that the "jurisdictional issue turns on a rather straightforward question of statutory interpretation: whether a promise to *forgo* consumption of electricity that would have been purchased in the retail electricity market unambiguously constitutes a "sale of electric energy" under section 201(b)(1)." Dissenting Op. at 227. The jurisdictional issue is not quite so narrow. In fact, even the Commission does not characterize the challenge this way and never offers an interpretation of § 201(b)(1), arguing instead that demand response resources are direct participants in wholesale markets. *See* FERC Br. 34–40. Though our review is deferential, even if we reached *Chevron* step two, we could not defer to an interpretation the agency has not offered.

In any event, we do not base our conclusion on the "any other sales" language of § 201(b)(1). Rather, we look to the statutory scheme as a whole and find that demand response, while not necessarily a retail *sale*, is indeed part of the retail *market*, which, *LLC v. Amalgamated Bank*, ––– U.S. ––––, 132 S.Ct. 2065, 2071, 182 L.Ed.2d 967 (2012); sections 205 and 206 do not constitute a "clear and specific grant of jurisdiction." Indeed, the Commission agrees its jurisdiction to regulate practices "affecting" rates does not "trump[ ] the express limitation on its authority to regulate non-wholesale sales." FERC Br. 34–35. Otherwise, FERC could engage in direct regulation of the retail market whenever the retail market affects the wholesale market, which would render the retail market prohibition useless. *Cf. Morpho Detection, Inc. v. TSA*, 717 F.3d 975, 981 (D.C.Cir.2013) (declining to "adopt a reading that would render the . . . general rule a nullity").

In addition, if FERC's arguments are followed to their logical conclusions, price-responsive demand response—retail demand response in "FERC speak"—would also affect jurisdictional rates in the same way as the type of demand response at issue in FERC's rule here, and FERC's authority regarding demand response would be almost limitless. Although the current rule leaves price-responsive demand untouched, nothing would stop FERC from expanding this regulation and encroaching further on state authority in the future.

Thus, FERC can regulate practices affecting the wholesale market under §§ 205 and 206, provided the Commission is not directly regulating a matter subject to state control, such as the retail market. *Cf. Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 479 (D.C.Cir.2009) (finding FERC could regulate the installed capacity market under its affecting

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as the statute and case law confirm, is exclusively within the state's jurisdiction.

jurisdiction because FERC did not engage in direct regulation of an area subject to exclusive state control).[2]

The fact that the Commission is only "luring" the resource to enter the market instead of requiring entry does not undercut the force of Petitioners' challenge. The lure is change of the retail rate. Demand response—simply put—is part of the retail market. It involves *retail* customers, their decision whether to purchase *at retail*, and the levels of *retail* electricity consumption. If FERC had directed ISOs to give a credit to any consumer who reduced its expected use of retail electricity, FERC would be directly regulating the retail rate. At oral argument, the Commission conceded crediting would be an impermissible intrusion into the retail market. *See* Oral Arg. Tape, at 27:15. Ordering an ISO to compensate a consumer for reducing its demand is the same in substance and effect as issuing a credit.[3] Thus, while it is true

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[2] *Connecticut Department of Public Utility Control v. FERC*, 569 F.3d 477 (D.C.Cir.2009), does not sanction FERC's rule. In *Connecticut*, FERC raised the capacity requirement and incidentally incentivized construction of more generation facilities, which are subject to state control; here, the Commission's rule reaches directly into the retail market to draw retail consumers into its scheme. Here, FERC's incentive is not merely a logical byproduct of the rule; it is the rule. According to the Dissent, "FERC can indirectly incentivize action that it cannot directly require so long as it is otherwise acting within its jurisdiction." Dissenting Op. at 234. We agree *Connecticut* cannot control where FERC has *directly* incentivized action it cannot directly require.

[3] The agency's concession contradicts the Dissent's contention that FERC can regulate demand response here because "non-consumption [does not] constitute an 'other sale,'" Dissenting Op. at 233.

demand response can occur in two ways—through a response to either price change or incentive payments—nothing about the latter makes it "wholesale." A buyer is a buyer, but a reduction in consumption cannot be a "wholesale sale." FERC's metaphysical distinction between price-responsive demand and incentive-based demand cannot solve its jurisdictional quandary.

Nor does FERC's reliance on a statement of congressional policy from the Energy Policy Act of 2005 save its rule. FERC insists its actions "are consistent with Congressional policy requiring federal level facilitation of demand response, because this final rule is designed to remove barriers to demand response participation in the organized wholesale energy markets." Order 745, 2011 WL 890975, at *30. FERC's reliance on this language is perplexing; if anything, the policy statement supports the opposite conclusion, that Congress intended demand response resources to be regulated by states, as part of the retail market.

The Energy Policy Act of 2005 confirms the national policy of encouraging and facilitating "the deployment of [time-based pricing and other demand response] technology and devices that enable electricity customers to participate in such pricing and demand response systems . . . and [eliminating] unnecessary barriers to demand response participation in energy, capacity and ancillary service markets." Pub.L. No. 109–58, § 1252(f), 119 Stat. 594, 966 (2005). As an initial matter, even if § 1252(f) supports FERC's authority, the Commission cannot rely on the section for an independent source of power. Policy statements like § 1252(f) "are just that—statements of policy. They are not delegations of regulatory authority." *See Comcast*

Corp. v. FCC, 600 F.3d 642, 654 (D.C.Cir.2010); *cf. New York*, 535 U.S. at 22, 122 S.Ct. 1012 (finding that a "mere policy declaration . . . cannot nullify a clear and specific grant of jurisdiction"). Thus, the relevant sections of the Energy Policy Act of 2005 can only be used to "help delineate the contours of statutory authority." *Comcast Corp*., 600 F.3d at 654. And here, those contours do not encompass federal regulation of demand response.

FERC latches onto the language in § 1252(f) requiring elimination of "unnecessary barriers to demand response participation in energy . . . service markets" to support its claim that Order 745 advances congressional policy. *See* FERC Br. 40. In Order 745, however, FERC went far beyond removing barriers to demand response resources. Instead of simply "removing barriers," the rule draws demand response resources into the market and then dictates the compensation providers of such resources must receive.

We think the title of the section is noteworthy: "Federal *Encouragement* of Demand Response Devices." (emphasis added). Pub.L. No. 109–58, § 1252(f), 119 Stat. 594, 966. "To encourage" is not "to regulate." Although the title is "not dispositive of the provision's meaning," "it is not too much to expect that it has something to do with the subject matter" of the section. *See CAISO*, 372 F.3d at 399. And here, "review of the statutory text reveals that [the title] has everything to do with the subject matter." *See id*. The section dictates demand response is to be "encouraged" and "facilitated," not directly regulated as Order 745 proposes.

This is obvious when § 1252(f) is read in tandem with § 1252(e), "Demand Response and Regional Coordination," which declares it the "policy of the

United States to encourage States to coordinate, on a regional basis, State energy policies to provide reliable and affordable demand response services to the public." Pub.L. No. 109–58, § 1252(e), 119 Stat. 594, 966. This language underscores that states, not the Commission, regulate demand response. Indeed, § 1252(e) goes on to note FERC should "provide technical assistance to States and regional organizations . . . in . . . developing plans and programs to use demand response to respond to peak demand or emergency needs." *Id*. The Commission is also to prepare an annual report, assessing demand response resources. *Id*. Thus, the Energy Policy Act clarifies FERC's authority over demand response resources is limited: its role is to assist and advise state and regional programs.

Even more importantly, the Energy Policy Act statements show Congress understood the importance of demand response resources to the wholesale market—an importance Petitioners do not dispute. Yet, despite this significant impact on the wholesale market, Congress left regulation of this aspect of retail demand up to the states, rather than to the federal government.

Because the Federal Power Act unambiguously restricts FERC from regulating the retail market, we need not reach *Chevron* step two. But even if we assumed the statute was ambiguous—as Judge Edwards argues, we would find FERC's construction of it to be unreasonable for the same reasons we find the statute unambiguous. Because FERC's rule entails direct regulation of the retail market—a matter exclusively within state control—it exceeds the Commission's authority.

IV [sic]

Alternatively, even if we *assume* FERC had statutory authority to execute the Rule in the first place, Order 745 would still fail because it was arbitrary and capricious.

Under the APA, we must set aside orders that are "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law." 5 U.S.C. § 706(2)(A). In particular, "it most emphatically remains the duty of this court to ensure that an agency engage the arguments raised before it," *NorAm Gas Transmission Co. v. FERC*, 148 F.3d 1158, 1165 (D.C.Cir.1998), including the arguments of the agency's dissenting commissioners, *Am. Gas Ass'n v. FERC*, 593 F.3d 14, 19 (D.C.Cir.2010); *see also Kamargo Corp. v. FERC*, 852 F.2d 1392, 1398 (D.C.Cir.1988) ("We recognize that this case presents a difficult problem for the Commission, but we think it has no alternative but to confront the questions raised by the [commissioner's] dissent.").

A review of the record reveals FERC failed to properly consider—and engage—Commissioner Moeller's reasonable (and persuasive) arguments, reiterating the concerns of Petitioners and other parties, that Order 745 will result in unjust and discriminatory rates. Moeller argued Order 745 "overcompensat[es]" demand response resources because it "requires that demand resource[s] be paid the full LMP *plus* be allowed to retain the savings associated with [the provider's] avoided retail generation cost." Demand Response Compensation in Organized Wholesale Energy Markets: Order on Rehearing and Clarification, 137 FERC ¶ 61,215, 2011 WL 6523756, at *38 (Dec. 15, 2011) [hereinafter Order 745–A] (Moeller, dissenting); *see also* Pet'rs Br. 45–50. The Commission then responded that demand response resources are comparable to generation resources and should therefore receive the same level of compensation. Order 745–A, 2011 WL 6523756, at *14–15. Yet comparable contributions cannot be the reason for equal compensation, when generation resources are incomparably saddled with generation costs. Nor can FERC justify its current overcompensation by pointing to past under-compensation.[4] Although we need not delve now into the dispute among experts, *see*, *e.g*., Br. of Leading Economists as *Amicus Curiae* in Support of Pet'rs, the potential windfall to demand response resources seems troubling, and the Commissioner's concerns are certainly valid. Indeed, "overcompensation cannot be just and reasonable," Order 745–A, 2011 WL 6523756, at *38 (Moeller, dissenting), and the Commission has not adequately explained how their system results in just compensation.

The Commission cannot simply talk around the arguments raised before it; reasoned decisionmaking requires more: a "direct response," which FERC failed to provide here. *See Am. Gas Ass'n*, 593 F.3d at 20. Thus, if FERC thinks its jurisdictional struggles are its only concern with Order 745, it is mistaken. We would still vacate the Rule if we engaged the Petitioners' substantive arguments.

[4] Similarly, the hope that demand response resources will use the expected windfall for "capital improvements," *see* Dissenting Op. at 237, does not respond to Petitioner's concerns that the overcompensation is unfair and discriminatory.

V [sic]

Ultimately, given Order 745's direct regulation of the retail market, we vacate the rule in its entirety as *ultra vires* agency action.

For the reasons set forth above, we vacate and remand the rulings under review.

So ordered.

EDWARDS, Senior Circuit Judge, dissenting:

Under the Federal Power Act, regulatory authority over the nation's electricity markets is bifurcated between the States and the federal government. In simplified terms, the Federal Energy Regulatory Commission ("FERC" or "Commission") has authority over wholesale electricity sales but not retail electricity sales, with the latter solely subject to State regulation. *See* 16 U.S.C. § 824(a), (b)(1). The consolidated petitions before the court call on us to parse this jurisdictional line between FERC's wholesale jurisdiction and the States' retail jurisdiction—a line which this court and the Supreme Court have recognized is neither neat nor tidy. *See New York v. FERC*, 535 U.S. 1, 16, 122 S.Ct. 1012, 152 L.Ed.2d 47 (2002) ("[T]he landscape of the electric industry has changed since the enactment of the [Federal Power Act], when the electricity universe was 'neatly divided into spheres of retail versus wholesale sales.'" (quoting *Transmission Access Policy Study Grp. v. FERC*, 225 F.3d 667, 691 (D.C.Cir.2000))).

Petitioners challenge Order 745, a rule imposing certain compensation requirements on the administrators of the nation's wholesale electricity markets. *See* Order 745, *Demand Response Compensation in Organized Wholesale Energy Markets*, 134 FERC

¶ 61,187, 2011 WL 890975, at *1 (Mar. 15, 2011). The rule requires these wholesale-market administrators—called Regional Transmission Organizations ("RTOs") and Independent System Operators ("ISOs")—to compensate so-called "demand response resources" at a specified price when certain conditions are met. As relevant here, "demand response resources" are essentially electricity consumers, often bundled together by a third-party aggregator, who agree to reduce their electricity consumption in exchange for incentive payments. *See* 18 C.F.R. § 35.28(b)(4)-(5). The pun scattered throughout the record is that while generators produce megawatts, consumers produce "negawatts." In effect, Order 745 requires that, at certain times, megawatts and negawatts receive the same amount of payment in wholesale markets, an amount called the "locational marginal price" or "LMP."

Although the challenged rule requires ISOs and RTOs to pay demand response resources a specified compensation (LMP), this requirement is applicable only when two conditions are met: (1) when the demand response resource is capable of balancing supply and demand in the wholesale market, and (2) when compensating the demand response resource is cost-effective under a "net benefits test" prescribed by the rule. The specific mechanics of these conditions and of the "net benefits test" are less important than what they accomplish. The critical point here is that, because of the specified conditions, Order 745 requires compensation of demand response resources *only when* their participation in a wholesale electricity market actually lowers the market-clearing price for wholesale electricity.

With these basics in hand, it is easy to see why FERC stated in its rulemaking that "jurisdiction over demand response is a complex matter that lies at the confluence of state and federal jurisdiction." Order 745, 2011 WL 890975, at *30. On one view, the demand response resources subject to the rule directly affect the *wholesale* price of electricity. That is, the final rule's conditions operate to ensure that *every* negawatt of forgone consumption receiving compensation reduces both the quantity of electricity produced and its wholesale price. Focusing on this direct effect—direct, it bears repeating, because under the rule's conditions *all* demand response resources receiving compensation reduce the market-clearing price—it is easy to conceive of Order 745 as permissibly falling on the *wholesale* side of the wholesale-retail jurisdictional line. On another view, however, the electricity not consumed thanks to the rule's compensation payments would have been consumed first in a retail market. Focusing on the market in which the consumption *would have occurred* in the first instance, one can conceive of Order 745 as impermissibly falling on the *retail* side of the jurisdictional line.

The task for this court, of course, is not to divine from first principles whether a demand response resource subject to Order 745 is best considered a matter of wholesale or retail electricity regulation. Rather, our task is one of statutory interpretation within the familiar *Chevron* framework. *See Chevron U.S.A. Inc. v. Natural Res. Def. Council, Inc.*, 467 U.S. 837, 842–44, 104 S.Ct. 2778, 81 L.Ed.2d 694 (1984); *see also Cal. Indep. Sys. Operator Corp. (CAISO) v. FERC*, 372 F.3d 395, 399–400 (D.C.Cir.2004). The Commission has interpreted the Federal Power Act to permit it to issue Order 745. And it falls to this court to determine whether the Act unambiguously "sp[eaks] to the precise question," 467 U.S. at 842, 104 S.Ct. 2778 (*Chevron* step one), and, if not, whether the Commission's interpretation is a permissible construction of the statute, *id*. at 843, 104 S.Ct. 2778 (*Chevron* step two).

Though the rule and its operation are highly technical, the primary jurisdictional issue raised in these consolidated petitions turns on a rather straightforward question of statutory interpretation: whether a promise to *forgo* consumption of electricity that would have been purchased in a retail electricity market unambiguously constitutes a "sale of electric energy" under section 201(b)(1) of the Federal Power Act. 16 U.S.C. § 824(b)(1). If so, the Commission lacked jurisdiction to issue Order 745 because section 201(b)(1) of the Act states, in relevant part, that the "provisions of this subchapter shall apply . . . to the sale of electric energy at *wholesale* in interstate commerce, but . . . *shall not apply to any other sale of electric energy*." *Id*. (emphasis added).

The statute, to my mind, is ambiguous regarding whether forgone consumption constitutes a "sale" under section 201(b)(1). Because of this ambiguity, the Act is also ambiguous as to whether a rule requiring administrators of wholesale markets to pay a specified level of compensation for such forgone consumption constitutes "direct regulation" of retail sales that would contravene the limitations of section 201. *Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 481–82 (D.C.Cir.2009) (holding that FERC's approval of an Installed Capacity Requirement was not "*direct regulation*" of electrical generation facilities and, thus, did not violate section 201 (emphasis added)). Because the Act is ambiguous regarding FERC's authority to require ISOs and RTOs to pay demand response resources, we are obliged to defer under *Chevron* to the Commission's permissible construction of "a statutory ambiguity that concerns the scope of the agency's statutory authority (that is, its jurisdiction)." *City of Arlington v. FCC*, —— U.S. ——, 133 S.Ct. 1863, 1868, 1874–75, —— L.Ed.2d —— (2013).

Absent an affirmative limitation under section 201, there is no doubt that demand response participation in wholesale markets and the ISOs' and RTOs' market rules concerning such participation constitute "practice[s] . . . affecting" wholesale rates under section 206 of the Act. 16 U.S.C. § 824e(a); *see also id*. § 824d(a) (providing that "all rules and regulations affecting or pertaining to [wholesale] rates or charges shall be just and reasonable"). Petitioners' arguments to the contrary ignore the direct effect that the ISOs' and RTOs' market rules have on wholesale electricity rates squarely within FERC's jurisdiction. The Commission has authority to "determine the just and reasonable . . . practice" by setting a level of compensation for demand response resources that, in its expert judgment, will ensure that the rates charged in wholesale electricity markets are "just and reasonable." *Id*. § 824e(a). It was therefore reasonable for the Commission to conclude that it could issue Order 745 under the Act's "affecting" jurisdiction. *See id*. §§ 824e(a), 824d(a).

In addition to challenging FERC's jurisdiction, Petitioners argue that its decision to mandate compensation equal to the LMP was arbitrary and capricious. Petitioners believe that the LMP overcompensates demand response resources since they also realize savings from not having to purchase retail electricity. The Commission, Petitioners insist, should have set the compensation level at the LMP minus the retail cost of the forgone electricity. But the Commission's decision in this regard was reasonable and adequately explained.

For these reasons, explained below in greater detail, I respectfully dissent.

I. BACKGROUND

A. The Problem

To understand this case, one must appreciate the scope and significance of the problem FERC sought to address in Order 745. Three characteristics of the nation's electricity market go a long way toward framing the problem. *First*, electricity, unlike most commodities, cannot be stored for later use. There must instead be a continual, contemporaneous matching of supply to meet current electricity demand. *Second*, not all power plants are created equal: some are efficient and cheap; others, inefficient and expensive. *Third*, most retail consumers are charged a fixed price for electricity that does not adjust in the moment to temporary spikes in the cost of producing electricity.

The first two characteristics, in tandem, cause significant fluctuations in the cost of supplying electricity at different times of day. During periods of regular electricity consumption, only the efficient and cheap power plants need be deployed. But at hours of peak usage (*e.g.*, a summer afternoon in Washington, D.C. when countless air conditioners toil against the humidity and heat), the suppliers of electricity must marshal the least efficient and most costly power plants to match the soaring demand for electricity. It is because electricity cannot be efficiently stored that these periods of peak demand must be met with new generation and not stockpiled supply.

In a perfect market, or even in a well-functioning market, the skyrocketing cost of producing additional electricity at hours of peak usage would be reflected in temporarily higher prices charged to consumers. In turn, this increased price would reduce the megawatts of electricity demanded, as some individuals and businesses would, for example, turn off their air conditioners to save money. The market would thereby reach an efficient equilibrium.

But here is where the third characteristic of electricity markets comes in. Retail electricity prices are generally regulated to remain constant over longer periods of time. That is, consumers do not pay different amounts during different hours of the day, notwithstanding the sharply vacillating cost of producing electricity. Electricity demand thus does not respond to time-sensitive price signals. As a result, there are times when people and businesses consume electricity that costs more to produce than it is worth to them to consume. This is inefficient.

Wholesale electricity markets, which are under FERC's jurisdiction, suffer the same inefficiency. Since retail demand is not price-responsive, the aggregate amount of electricity demanded in the wholesale market by the entities that serve retail customers is also uncoupled from the time-specific price of supplying electricity. In economic terms, the demand for electricity in the wholesale market is inelastic. *See* Order 745–A, *Demand Response Compensation in Organized Wholesale Energy Markets*, 137 FERC ¶ 61,215, 2011 WL 6523756, at *9 (Dec. 15, 2011).

The Commission recognizes the problem. As it observed in its order denying requests for rehearing of Order 745,

> [a] properly functioning market should reflect both the willingness of sellers to sell at a price and the willingness of buyers to purchase at a price. In an RTO- or ISO-run market, however, buyers are generally unable to directly express their willingness to pay for a product at the price offered. As discussed later, RTOs and ISOs cannot isolate individual buyers' willingness to pay which results in extremely inelastic demand.

Id.; *see also* Order 745, 2011 WL 890975, at *1 ("[A] market functions effectively *only when* both supply and demand can meaningfully participate." (emphasis added)).

B. FERC's Solution

Having identified a problem in the wholesale electricity market, the Commission has a statutory obligation to do what it can to fix it. That is because FERC is charged under the Federal Power Act with ensuring that wholesale electricity rates are "just and reasonable." 16 U.S.C. §§ 824d(a), 824e(a). It must ensure that all "rates and charges made, demanded, or received by any public utility for *or in connection with* the . . . sale of electric energy subject to the jurisdiction of the Commission" are "just and reasonable." *Id.* § 824d(a) (emphasis added); *see also id.* § 824(a). And when FERC determines that a "practice . . . affecting" such a rate is unjust or unreasonable, it must itself determine and fix "the just and reasonable . . . practice . . . to be thereafter observed." *Id.* § 824e(a).

Consistent with its statutory duty and in view of the market distortions caused by inelastic wholesale demand, the Commission has initiated a series of reforms to open wholesale markets to "demand response resources." For our purposes, "demand response resources" are resources that are capable of reducing "the consumption of electric energy by customers from their expected consumption in response . . . to incentive payments designed to induce lower consumption of electric energy." 18 C.F.R. § 35.28(b)(4)-(5). Put simply, demand response resources agree not to purchase electricity in exchange for payment.

The basic premise of FERC's demand-response reforms is that there are two ways that wholesale-market administrators (*i.e.*, ISOs and RTOs) can balance wholesale supply and demand: by increasing the supply of electricity *or* by decreasing the demand for it. *See* Order 745–A, 2011 WL 6523756, at *14. An ISO or RTO reduces wholesale demand when it pays a demand response resource because that resource will forgo electricity consumption in the retail market, which, in turn, will lead to fewer megawatts of electricity being demanded in the aggregate in that ISO's or RTO's wholesale market. At certain times (*e.g.*, summer afternoons in Washington, D.C.), paying incentive payments to induce consumers not to consume electricity may be cheaper than paying generators to produce more power; negawatts, in such circumstances, are the cheaper alternative. And because, functionally, there is little difference to wholesale-market administrators between a megawatt and a negawatt (both assist equally in the administrator's task of bringing wholesale demand and supply into equipoise), demand response resources are capable of competing directly with traditional generation resources so long as the appropriate market rules are in place.

For some years now, FERC has recognized that the direct participation of demand response resources in wholesale markets improves the functioning of these markets in several respects. First, it lowers wholesale prices because "lower demand means a lower wholesale price." Order 719–A, *Wholesale Competition in Regions with Organized Electric Markets*, 128 FERC ¶ 61,059, 2009 WL 2115220, at *12 (July 16, 2009). Second, it mitigates the market power of suppliers of electricity because they have to compete with demand response resources and adjust their bidding strategy accordingly. *See id*. ("[T]he more demand response is able to reduce peak prices, the more downward pressure it places on generator bidding strategies by increasing the risk to a supplier that it will not be dispatched if it bids a price that is too high."). Third, demand response "enhances system reliability," for example, by "reducing electricity demand at critical times (e.g., when a generator or a transmission line unexpectedly fails)." *Id*. at *12 & n. 76; *see also* Order 745–A, 2011 WL 6523756, at *6 ("[D]emand response generally can be dispatched by the [ISO or RTO] with a minimal notice period, helping to balance the electric system in the event that an unexpected contingency occurs.").

The benefits of demand response participating in wholesale markets are beyond reproach. Commissioner Moeller, who dissented in Order 745, put it best:

> While the merits of various methods for compensating demand response were discussed at length in the course of this rulemaking, nowhere did I review any comment or hear any testimony that questioned the benefit of having demand response resources participate in the organized wholesale energy markets. *On this point, there is no debate.*

> The fact is that demand response plays a very important role in these markets by providing significant economic, reliability, and other market-related benefits.

Order 745, 2011 WL 890975, at *34 (emphasis added) (Moeller, dissenting).

It is no surprise, then, that FERC has initiated a series of reforms to open up its markets to demand response, on the theory that doing so helps to ensure "just and reasonable" wholesale rates by improving how these markets function in the three ways just mentioned. *See* Order 890, *Preventing Undue Discrimination and Preference in Transmission Service*, 72 Fed.Reg. 12,226, 12,378 (Mar. 15, 2007); Order 719, *Wholesale Competition in Regions with Organized Electric Markets*, 73 Fed.Reg. 64,100 (Oct. 28, 2008); *see also* Br. for Resp't at 11–13 (providing overview of these rulemakings); *id*. at 12 (noting that, before Order 719, FERC had approved proposals by various ISOs and RTOs "to allow demand response participation in their ancillary services markets" (citations omitted)).

In particular, in Order 719 FERC required ISOs and RTOs to "accept bids from demand response resources in RTOs' and ISOs' markets for certain ancillary services on a basis comparable to other resources" and, in certain circumstances, to "permit an aggregator of retail customers . . . to bid demand response on behalf of retail customers directly into the organized energy market." Order 719–A, 2009 WL 2115220, at *1. But FERC placed an important condition on this requirement; ISOs and RTOs were required to accept bids from demand response "unless not permitted by the laws or regulations of the relevant electric retail regulatory authority." 18 C.F.R. § 35.28(g)(1)(i)(A), (iii); Order 719–A, 2009 WL 2115220, at *13. Finally, recognizing that "further reforms may be necessary to eliminate barriers to demand response in the future," FERC further ordered ISOs and RTOs to "assess and report on any remaining barriers to comparable treatment of demand response resources that are within the Commission's jurisdiction." Order 719–A, 2009 WL 2115220, at *1.

And further reforms were indeed necessary. Prior to issuing Order 745, ISOs and RTOs had differing practices concerning the level of compensation to be paid to demand response resources in their markets. Order 745, 2011 WL 890975, at *4. The Commission found that many ISOs and RTOs undercompensated demand response resources in certain circumstances. *See id*. at *16. It reached this finding in light of existing barriers to demand response participation in wholesale markets, including "the lack of market incentives to invest in enabling technologies that would allow electric customers and aggregators of retail customers to see and respond to changes in marginal costs of providing electric service as those costs change." *Id*.; *see also id*. ("[T]he inadequate compensation mechanisms in place today in wholesale energy markets fail to induce sufficient investment in demand response resource infrastructure and expertise that could lead to adequate levels of demand response procurement. *Without sufficient investment in the development of demand response, demand response resources simply cannot be procured because they do not yet exist as resources*. Such investment will not occur so long as compensation undervalues demand response resources." (emphasis added) (quoting a commenter)).

Order 745 sought to correct the under-compensation problem by mandating that ISOs and RTOs pay demand response resources the same market price that they pay to generators, *i.e.*, LMP. But it limited this compensation requirement to circumstances where two specific conditions are met. LMP-compensation would be required only when (1) "the demand response resource [is] able to displace a generation resource in a manner that serves the RTO or ISO in balancing supply and demand," and (2) "the payment of LMP . . . [is] cost-effective, as determined by [a] net benefits test." *Id*. at *13; *see also* 18 C.F.R. § 35.28(g)(1)(v)(A).

FERC understood that it had authority to correct the under-compensation problem because, in the absence of adequate compensation, too few demand response resources affirmatively bid into the wholesale markets. And such participation is necessary for the market to function rationally and reach "just and reasonable" rates. As FERC stated:

> We find, based on the record here that, when a demand response resource has the capability to balance supply and demand as an alternative to a generation resource, and when . . . paying LMP to that demand response resource is shown to be cost-effective as determined by the net benefits test described herein, payment by an RTO or ISO of compensation other than the LMP is unjust and unreasonable. *When these conditions are met, we find that payment of LMP to these resources will result in just and reasonable rates for ratepayers*.

Order 745, 2011 WL 890975, at *13 (emphasis added).

II. ANALYSIS

A. Jurisdiction

Petitioners argue that Order 745 is "in excess" of FERC's "statutory jurisdiction." Br. of Pet'rs Elec. Power Supply Ass'n, et al. ("Br. of Pet'rs") at 27 (citing

5 U.S.C. § 706(2)(C)). We evaluate this contention under *Chevron* and defer to FERC's permissible construction of its authorizing statute, regardless of "whether the interpretive question presented is 'jurisdictional.'" *City of Arlington*, 133 S.Ct. at 1874–75; *see also Connecticut*, 569 F.3d at 481. The proper question is thus whether the Act *unambiguously* forecloses FERC from issuing Order 745 under its "affecting" jurisdiction. *See* 16 U.S.C. § 824e; *Chevron*, 467 U.S. at 842, 104 S.Ct. 2778.

FERC's explanation of its jurisdiction under the Federal Power Act is straightforward and sensible. FERC has the authority and responsibility to correct any "practice . . . affecting" wholesale electricity rates that the Commission determines to be "unjust" or "unreasonable." 16 U.S.C. § 824e(a); *see also id*. § 824d(a). In its view, the ISOs' and RTOs' rules governing the participation of demand response resources in the nation's wholesale electricity markets are "practices affecting [wholesale electricity] rates." Order 745–A, 2011 WL 6523756, at *10 (quoting 16 U.S.C. §§ 824d, 824e). That is, an ISO's or RTO's market rules governing how a demand response resource may compete in its wholesale market, including the terms by which a demand response resource is to be compensated in the market, are "practices affecting" that wholesale market's rates for electricity. And FERC has determined that an ISO's or RTO's "practice" is unjust and unreasonable to the degree that it inadequately compensates demand response resources capable of supplanting more expensive generation resources. *See id*. at *36. As explained above, FERC has found that demand response improves the functioning of wholesale markets by (1) lowering the wholesale price of electricity, (2) exerting downward pressure on generators' market power, and (3) enhancing system reliability.

FERC's explanation is consistent with our case law. In *Connecticut*, we considered whether FERC has jurisdiction to review an ISO's capacity charges. 569 F.3d at 478–79. Capacity is not electricity but the ability to produce it when needed, and in *Connecticut* the ISO had established a market where capacity providers—generators, prospective generators, and demand response resources—competitively bid to meet the ISO's capacity needs three years in the future. *Id*. at 479–81. Generation, like retail sales, is expressly the domain of State regulation under section 201, 16 U.S.C. § 824(b)(1), and the petitioners argued that by increasing the overall capacity requirement the ISO was improperly requiring the installation of new generation resources. 569 F.3d at 481. We disagreed and held that FERC had "affecting" jurisdiction under section 206 because "capacity decisions . . . affect FERC-jurisdictional transmission rates for that system without directly implicating generation facilities." *Id*. at 484. That the capacity requirement helped to "find the right price" was enough of an effect to satisfy section 206. *Id*. at 485.

Petitioners' specific arguments against FERC's exercising jurisdiction are unpersuasive. *First*, Petitioners note that section 201 of the Act establishes a clear jurisdictional line between "the sale of electric energy at wholesale in interstate commerce," which is properly the subject of FERC's jurisdiction, and "any other sale of electric energy." Br. of Pet'rs at 27–28 (citing 16 U.S.C. § 824(a), (b)(1)). According to Petitioners, the Commission has transgressed this line because it "has ordered ISOs and RTOs to pay *retail customers* for reducing their *retail purchases* of electricity." *Id*. at 28.

But this argument mischaracterizes the rule and papers over a key ambiguity. First, the mischaracterization: Petitioners are wrong inasmuch as they imply that FERC requires *all* ISOs and RTOs to pay demand response resources a minimum level of compensation (LMP). The compensation requirement promulgated in Order 745 does not apply unless an ISO or RTO "has a tariff provision permitting demand response resources to participate as a resource in the energy market." 18 C.F.R. § 35.28(g)(1)(v). And the regulation's requirement that ISOs and RTOs accept bids from demand response resources comes with a key caveat: the requirement applies "unless not permitted by the laws or regulations of the relevant electric retail regulatory authority." *Id*. § 35.28(g)(1)(i)(A); *see also id*. § 35.28(g)(1)(iii). In other words, there is a carve-out from the compensation requirement for ISOs and RTOs in States where local regulatory law stands in the way. Thus, the Order preserves State regulation of retail markets. This is hardly the stuff of grand agency overreach.

More fundamentally, Petitioners' argument founders on a statutory ambiguity they ignore. Section 201 makes clear that FERC may regulate "the sale of electric energy at wholesale in interstate commerce" but not "any other *sale* of electric energy." 16 U.S.C. § 824(b)(1) (emphasis added). The demand response at issue here is forgone consumption, which is no "sale" at all. Perhaps the phrase "any other sale of electric energy" could be interpreted to include *non*-sales that *would have been* sales in the retail market, but it certainly does not *require* such a reading. It is reasonable to categorize demand response as neither a retail sale nor wholesale sale under the Federal Power Act. And on this understanding, section 201 "says nothing about" FERC's power to review compensation rates for demand response in wholesale electricity markets. *Connecticut*, 569 F.3d at 483.

Nor is Petitioners' argument under section 201 made any stronger by reference to subsection (a). This prefatory subsection states that while "Federal regulation . . . of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce is necessary in the public interest," federal regulation should "extend only to those matters which are not subject to regulation by the States." 16 U.S.C. § 824(a). But the Supreme Court has made clear that "the precise reserved state powers language in § 201(a)" is a "*mere policy declaration* that cannot nullify a clear and specific grant of jurisdiction, *even if the particular grant seems inconsistent with the broadly expressed purpose*." *New York*, 535 U.S. at 22, 122 S.Ct. 1012 (emphasis added) (internal quotation marks omitted). And, as I discuss below, section 206's specific grant of "affecting" jurisdiction quite clearly authorized FERC to issue Order 745.

The most that can be said of section 201 is that it commits regulation of retail *sales* to the States and regulation of wholesale *sales* to the Commission. And while it is true that the forgone consumption would have been purchased in the first instance in the retail market, it does not follow from this fact that non-consumption constitutes an "other sale" under section 201(b). There was no sale, period. And the statute does not give a clear indication that Congress intended to foreclose FERC from regulating non-sales that have a direct effect on the wholesale markets under FERC's jurisdiction.

Even assuming that the Federal Power Act requires demand response resources to be considered inextricably part of retail "sales" subject solely to State regulation, Order 745 does not engage in the type of "direct regulation" that would violate section 201. *See Connecticut*, 569 F.3d at 481. Order 745 does not require anything of retail electricity consumers and leaves it to the States to decide whether to permit demand response. All Order 745 says is that *if* a State's laws permit demand response to be bid into electricity markets, and *if* a demand response resource affirmatively decides to participate in an ISO's or RTO's wholesale electricity market, and *if* that demand response resource would in a particular circumstance allow the ISO or RTO to balance wholesale supply and demand, and *if* paying that demand resource would be a net benefit to the system, *then* the ISO or RTO must pay that resource the LMP. That is it. This requirement will no doubt affect how much electricity is consumed by a small subset of retail consumers who elect to participate as demand response resources *in wholesale markets*. But that fact does not render Order 745 "direct regulation" of the retail market. Authority over retail rates and over whether to permit demand response remains vested solely in the States.

In this respect, Order 745 is similar to the capacity rule in *Connecticut* that we found did not directly regulate generation facilities. 569 F.3d at 482. Even though increasing the capacity requirement incentivized the procurement of additional resources, including new generation facilities, to meet the higher requirement, we recognized that States retained their ultimate authority over the construction of new generation facilities. *Id*. at 481–82. And because the capacity requirements could be met in other ways aside from building new generators (*e.g*., through demand response or capacity contracts), it was irrelevant that "public utilities . . . overwhelmingly responded to [increased capacity requirements] by choosing to allow construction of new facilities over other alternatives." *Id*. at 482. The lesson of *Connecticut* is that FERC can indirectly incentivize action that it cannot directly require so long as it is otherwise acting within its jurisdiction—and that doing so does not constitute impermissible direct regulation of an area reserved to the States. So too here: Order 745 may encourage more demand response, but States retain the ultimate authority to approve the practice.

Second, Petitioners argue that the FERC's "affecting" jurisdiction under sections 205 and 206 of the Act "does not extend so far as to allow the Commission to regulate directly the retail services that are expressly carved out from the scope of its jurisdiction." Br. of Pet'rs at 30–31 (citing 16 U.S.C. § 824(a), (b)(1)). To a large degree, this argument simply rehashes Petitioners' erroneous reading of section 201 and fails for the reasons just described. Demand response resources are promises to *forgo* consumption of electricity and therefore are not retail "sales." This is not changed by the fact that forgone consumption would have taken place in the first instance in a retail market. Because of this, the Commission's asserting "affecting" jurisdiction over demand response does not, as Petitioners suggest, "nullify[ ]" a limitation set forth in section 201. *Id*. at 32.

To be sure, section 206 cannot be read to displace *unambiguous* jurisdictional limits imposed by section 201(b). Suppose, for example, that FERC issued a rule requiring ISOs and RTOs to condition all wholesale sales of electricity on load-serving entities' agreeing to charge retail customers with real-time pricing that adjusted hourly for variations in the cost of producing electricity. Such a rule would unambiguously regulate each retail "sale" because it would mandate a particular form of compensation for *actual*—not counterfactual—retail sales. Thus, while price-responsive retail pricing would no doubt "affect" the wholesale rate, FERC could not claim jurisdiction under sections 205 and 206 because the subchapter which includes these sections "shall not apply to any other *sale* of electric energy." 16 U.S.C. § 824(b)(1) (emphasis added). This example plainly differs from the present case because demand response resources are forgone sales or non-sales, and therefore it is at best ambiguous whether the limitation in section 201(b) applies. *See Connecticut*, 569 F.3d at 483 ("Section 201 prohibits the Commission from regulating generation facilities but says nothing about its power to review the capacity requirements that an [ISO] imposes on member [utilities].").

To bolster their case, Petitioners invoke the specter of limitless federal authority if FERC is permitted to exercise "affecting" jurisdiction to issue Order 745. They caution that "the Commission's expansive interpretation of its 'affecting' jurisdiction would allow it to regulate any number of activities—such as the purchase or sale of steel, fuel, labor, and other inputs influencing the cost to generate or transmit electricity—merely by redefining the activities as 'practices' that affect wholesale rates." Br. of Pet'rs at 33.

This argument cannot carry the day because it ignores at least two important limits. It first ignores section 201's limit proscribing any "direct regulation" of retail sales (which would bar the hypothetical rule, discussed above, in which FERC tries to mandate that retail sales have dynamic, time-responsive pricing). *See Connecticut*, 569 F.3d at 481. It also ignores the limitations we announced in *CAISO*, 372 F.3d 395. There, we held that FERC exceeded its jurisdiction when it replaced the board members of an ISO on the theory that the composition of the ISO's board was a "practice ... affecting [a] rate" under section 206(a). *Id*. at 399. We held that "section 206's empowering of the Commission to assess the justness and reasonableness of practices affecting rates of electric utilities is limited to those methods or ways of doing things on the part of the utility that *directly affect* the rate or are closely related to the rate, not all those remote things beyond the rate structure that might in some sense indirectly or ultimately do so." *Id*. at 403 (emphasis added).

These limits foreclose the parade of horribles marshaled by Petitioners. Like replacing the ISO's board of directors in *CAISO*, FERC could not, consistent with Circuit precedent, regulate markets in steel, fuel, labor, and other inputs for generating electricity, which constitute "remote things beyond the rate structure that might in some sense indirectly or ultimately" affect the wholesale rate of electricity. *Id*.; *see also Calpine Corp. v. FERC*, 702 F.3d 41, 47 (D.C.Cir.2012) (affirming FERC's determination that it lacked "affecting" jurisdiction over station power, which is a necessary input to energy production, because there was not a "sufficient nexus with wholesale transactions" (internal quotation marks omitted) (citing *City of Cleveland v. FERC*, 773 F.2d 1368, 1376 (D.C.Cir.1985))); *City of Cleveland*, 773

F.2d at 1376 ("[T]here is an infinitude of practices affecting rates and service. The statutory directive must reasonably be read to require the recitation of only those practices *that affect rates and service significantly* . . . ." (emphasis added)).

Order 745 passes the *CAISO* test quite comfortably because the demand response resources subject to the rule have a quintessentially "direct" effect on wholesale rates. The rule's compensation requirement applies *only when* an ISO or RTO can use the demand response resource in lieu of a generation resource to balance supply and demand, *and only when* paying a demand response resource is cost-effective under the rule's net benefits test. 18 C.F.R. § 35.28(g)(1)(v)(A). Order 745 thus does not purport to regulate demand response writ large; its compensation requirement applies only when the demand response *by definition* alters the wholesale electricity price. That is about as "direct" an effect and as clear a "nexus" with the wholesale transaction as can be imagined. *See Calpine Corp*., 702 F.3d at 47; *CAISO*, 372 F.3d at 403; *City of Cleveland*, 773 F.2d at 1376. There can be little doubt that FERC has the authority to review the justness and reasonableness of rates that are so closely connected with the healthy functioning of its jurisdictional markets; this, as we said in *Connecticut*, is the "heartland of the Commission's section 206 jurisdiction." 569 F.3d at 483.

Third, Petitioners argue that the Commission's orders exceed its jurisdiction because "they unreasonably interfere with existing state and local programs addressing retail customer 'demand response.'" Br. of Pet'rs at 41. Any such effect, however, is merely incidental. As the Commission correctly observed, Order 745 "does not directly affect retail-level demand response programs, nor does it require that demand response resources offer into the wholesale market only. Indeed, the organized wholesale energy markets can and do operate simultaneously with retail-level programs . . . ." Order 745–A, 2011 WL 6523756, at *19. FERC's reforms in Order 745 run on a parallel track with State-level reforms. And to the degree that FERC's reforms incidentally affect parallel State-level initiatives, that does not render FERC's actions improper. *See Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277, 1280 (D.C.Cir.2007) (observing that FERC's authority to act within its statutory scope of jurisdiction "may, of course, impinge as a practical matter on the behavior of non-jurisdictional" entities).

* * *

To summarize: FERC's jurisdiction turns on two issues: (1) whether demand response is a retail "sale" or is otherwise unambiguously committed to State regulation under the Federal Power Act, and (2) whether sections 205 and 206 clearly grant jurisdiction to FERC to regulate how wholesale-market administrators compensate demand response resources that "directly affect" wholesale prices. Unless we inject quasi-philosophy into our *Chevron* analysis (what is the sound of one hand clapping? what is the true nature of a sale that was never made? of megawatts never consumed?), I think it clear that the Federal Power Act does not precisely address the first question; forgone consumption is not unambiguously a "sale," nor does the statute dictate that demand response be treated solely as a matter of retail regulation. And the second question is resolved, in my view, by the terms of Order 745 which narrowly apply *only* to demand response resources that by definition directly affect the wholesale rates of electricity. This falls squarely within the Commission's "affecting" jurisdiction. *See* 16 U.S.C. §§ 824d, 824e. The proper course for this court is to defer to the Commission's well-reasoned and permissible interpretation of its authority under the statute.

B. Level of Compensation

Petitioners also argue that Order 745 is arbitrary and capricious under 5 U.S.C. § 706(2)(A). In reviewing such claims, we consider whether FERC "examine[d] the relevant data and articulate[d] a satisfactory explanation for its action including a rational connection between the facts found and the choice made." *Motor Vehicle Mfrs. Ass'n of the U.S. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43, 103 S.Ct. 2856, 77 L.Ed.2d 443 (1983) (internal quotation marks omitted). We also afford significant deference to FERC in light of the highly technical regulatory landscape that is its purview. Indeed, "the Commission enjoys broad discretion to invoke its expertise in balancing competing interests and drawing administrative lines." *Am. Gas Ass'n v. FERC*, 593 F.3d 14, 19 (D.C.Cir.2010). And we "afford great deference to the Commission" in cases involving ratemaking decisions as the "statutory requirement that rates be 'just and reasonable' is obviously incapable of precise judicial definition." *Morgan Stanley Capital Grp. Inc. v. Pub. Util. Dist. No. 1*, 554 U.S. 527, 532, 128 S.Ct. 2733, 171 L.Ed.2d 607 (2008). Finally, to the extent that the Commission bases its actions on factual findings, such findings are conclusive if supported by substantial evidence. 16 U.S.C. § 825*l*(b).

Petitioners' chief complaint is that Order 745 sets the required compensation level for demand response at the LMP (recall: locational marginal price). LMP equals "the marginal value of an increase in supply or a reduction in consumption at each node within" an ISO's or RTO's wholesale market, and is the compensation generation resources generally receive. Order 745–A, 2011 WL 6523756, at *20. Petitioners complain that demand response resources already get the benefit of the forgone expense of retail electricity (abbreviated in the record as "G"). Therefore, Petitioners contend that, under FERC's rule, demand response resources effectively receive a "double payment": LMP plus G. Br. of Pet'rs at 47. According to Petitioners, requiring LMP compensation thus results in unjust and discriminatory overcompensation of demand response resources. *Id*. at 45–50; *see also* Order 745–A, 2011 WL 6523756, *38 (Moeller, dissenting).

It is of course true, as the majority observes, that FERC is "bounded by the requirements of reasoned decision making." *Am. Gas Ass'n*, 593 F.3d at 19. Therefore, FERC was required to provide a "direct response" to the Petitioners' and the dissenting Commissioner's concerns about overcompensation. *Id*. at 20. This is precisely what the Commission did in carefully explaining how Order 745's setting compensation at the LMP was neither discriminatory nor unjust.

To begin with, FERC provided a thorough explanation for why compensating demand response at the LMP (and not LMP-G) was neither unjust nor over-compensatory. It explained that such compensation was necessary to encourage an adequate level of demand response participation in wholesale markets in light of existing market barriers. *See* Order 745–A, 2011 WL 6523756, at *15 (noting that Petitioners "fail to acknowledge the market imperfections caused by the existing barriers to demand response"). That last part—the market barriers—is the key. The Commission has identified numerous barriers preventing adequate participation of demand response in wholesale markets. Order 745, 2011 WL 890975, at *16 & n. 122 (citing study). Indeed, citing record evidence, the Commission explained that "the inadequate compensation mechanisms in place today in wholesale energy markets fail to induce sufficient investment in demand response resource infrastructure and expertise that could lead to adequate levels of demand response procurement." *Id*. at *16 (quoting a commenter). FERC further explained that "a lack of incentives to invest in enabling technologies can be addressed by making additional investment resources available to market participants" and that paying LMP "to demand response will provide the proper level of investment resources available for capital improvements." Order 745–A, 2011 WL 6523756, at *16. In view of these barriers, and the value of demand response participation to ensuring "just and reasonable" wholesale rates, the Commission concluded that LMP was the appropriate level of compensation.

FERC sums it up well:

> The Commission acknowledged that noted experts differed on whether paying LMP in the current circumstances facing the wholesale electric market is a reasonable price. In determining that LMP is the just and reasonable price to pay for demand response, the Commission examined some of the previously recognized barriers to demand response that exist in current wholesale markets. These barriers create an inelastic

> demand curve in the wholesale energy market that results in higher wholesale prices than would be observed if the demand side of the market were fully developed. The Commission found that paying LMP when cost-effective may help remove these barriers to entry of potential demand response resources, and, thereby, help move prices closer to the levels that would result if all demand could respond to the marginal price of energy.

Id. at *17. This is a "direct response" to the points raised by the Petitioners. *Am. Gas Ass'n*, 593 F.3d at 20.

With respect to the argument that utilizing the LMP is somehow discriminatory because incomparable resources are paid comparable amounts, the Commission offered reasonable grounds for treating demand response as comparable to generation resources. The Commission observed that, from the perspective of an ISO or RTO, a demand response resource was comparable to a generation resource inasmuch as demand response is equally capable of balancing wholesale supply and demand. Order 745–A, 2011 WL 6523756, at *14. This is not the sum total of the explanation, however. In the same section of its order, the Commission explained that "examining cost avoidance by demand response resources is not consistent with the treatment of generation. In the absence of market power concerns, the Commission generally does not examine each of the costs of production for individual resources participating as supply resources in the organized wholesale electricity markets." *Id*. at *17; *see also id*. at *21. FERC continued: "we note that certain generators may receive benefits or savings in the form of credits or in other forms. In these cases, the generators realize a value of LMP plus the credit or savings, but ISOs or RTOs do not take such benefits or savings into account in determining how much to pay those resources." *Id*. at *17 n. 122. The point is that the comparability of compensation is assessed without regard to outside costs and credits; just as two generators are both compensated at the LMP even though only one might be receiving a tax credit for producing energy, so too with comparing demand response resources to generation resources. This was clearly explained, and it is reasonable.

This court has no business second-guessing the Commission's judgment on the level of compensation. *See La. Pub. Serv. Comm'n v. FERC*, 551 F.3d 1042, 1045 (D.C.Cir.2008) (noting that "[w]here the subject of our review is . . . a predictive judgment by FERC about the effects of a proposed remedy . . ., our deference is at its zenith"); *Pub. Serv. Comm'n of Ky. v. FERC*, 397 F.3d 1004, 1009 (D.C.Cir.2005) (holding that "more than second-guessing close judgment calls is required to show that a rate order is arbitrary and capricious" (citation omitted)); *Envtl. Action, Inc. v. FERC*, 939 F.2d 1057, 1064 (D.C.Cir.1991) ("[I]t is within the scope of the agency's expertise to make ... a prediction about the market it regulates, and a reasonable prediction deserves our deference notwithstanding that there might also be another reasonable view.").

Whatever policy disagreements one might have with Order 745's decision to compensate demand response resources at the LMP (and there are legitimate disagreements to be had), the rule does not fail for want of reasoned decisionmaking. FERC's judgment is owed deference because it has put forth a reasonable multi-step explanation of its decision to mandate LMP compensation. First, responsive demand is a necessary component of a well-functioning wholesale market, and FERC understood that its obligation to ensure just and reasonable rates required it to facilitate an adequate level of demand response participation in its jurisdictional markets. *See* Order 745, 2011 WL 890975, at *16. Second, FERC concluded that market barriers were inhibiting an adequate level of demand response participation. *See id*. Third, FERC concluded that mandating LMP would provide the proper incentives for demand response resources to overcome these barriers to participation in the wholesale market. *See id*.; *see also* Notice of Proposed Rule-making, *Demand Response Compensation in Organized Wholesale Energy Markets*, *reprinted in* J.A. 208, 220–21 (stating that "demand response resources react correspondingly to increases or decreases in payment" and citing study showing that switching from LMP to LMP-G compensation resulted in a 36.8% decrease in demand response participation in the ISO being studied).

III. CONCLUSION

FERC had jurisdiction to issue Order 745 because demand response is not unambiguously a matter of retail regulation under the Federal Power Act, and because the demand response resources subject to the rule directly affect wholesale electricity prices. *See* 16 U.S.C. §§ 824d, 824e. And the Commission's decision to require compensation equal to the LMP, rather than LMP-G, was not arbitrary or capricious. The majority disagrees on both points. The unfortunate consequence is that a promising rule of national significance—promulgated by the agency that has been authorized by Congress to address the matters in issue—is laid aside on grounds that I think are inconsistent with the statute, at odds with applicable precedent, and impossible to square with our limited scope of review. I therefore respectfully dissent.

APPENDIX B

FEDERAL ENERGY REGULATORY COMMISSION

Commission Opinions, Orders and Notices

Demand Response Compensation in
Organized Wholesale Energy Markets

Docket No. RM10-17-001
ORDER NO. 745-A
ORDER ON REHEARING AND CLARIFICATION
(Issued December 15, 2011)

Before Commissioners: Jon Wellinghoff, Chairman; Philip D. Moeller, John R. Norris, and Cheryl A. LaFleur.

1. In this order the Commission denies rehearing of Order No. 745 (Final Rule),[1] and grants in part and denies in part clarification regarding certain provisions of the order. Order No. 745 amended Commission regulations to require that a demand response resource participating in an organized wholesale energy market must be compensated for the service it provides at the market price for energy when the demand response resource has the capability to balance supply and demand as an alternative to a generation resource and when the dispatch of demand response resource is cost-effective.

I. Introduction

2. On March 15, 2011, the Commission issued Order No. 745, a Final Rule amending its regulations under the Federal Power Act (FPA) regarding demand response compensation in the Regional Transmission

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[1] *Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745, 76 Fed. Reg. 16,658 (Mar. 24, 2011), FERC Stats. & Regs. ¶ 31,322 (2011).

Organization (RTO) and Independent System Operator (ISO) day-ahead and real-time organized wholesale energy markets. The Commission determined that the Final Rule would help improve the functioning and competitiveness of organized wholesale energy markets, thereby ensuring just and reasonable rates in those markets. In the Final Rule, the Commission requires each RTO and ISO in which demand response participates in its energy market to pay a demand response resource the market price for energy, also referred to as the locational marginal price (LMP), when two conditions are met. First, the demand response resource must have the capability to balance supply and demand as an alternative to a generation resource. Second, dispatch of the demand response resource must be cost-effective as determined by a net benefits test.[2]

3. The Commission in the Final Rule also provided guidance about the net benefits test that it required RTOs and ISOs to include in their respective compliance filings, and on the formulation of such a test. As explained in the Final Rule, the net benefits test begins with an analysis of a RTO's or ISO's historical

[2] The Commission explained that a net benefits test is necessary because the dispatch of demand response resources may result in an increased cost per unit to load associated with the decreased amount of load that pays for the cost of energy purchased in the organized wholesale energy market. The Commission further explained that when the LMP is reduced and consumers realize a cost savings because of the participation of demand response resources in the energy market, and where this cost savings is of a sufficient amount to overcome the total amount that consumers pay for demand response resources at the LMP and the effect of the reduced quantity of load paying for the purchased supply resources, such a purchase of demand response resources is cost-effective.

supply curves grouped into monthly periods, from which a threshold point can be calculated. This threshold point corresponds to a point on the supply curve at which the benefit to load from the reduced LMP resulting from dispatching demand response resources exceeds the increased cost to load associated with the billing unit effect. The Commission stated in the Final Rule that it expects that the net benefits test would be satisfied, thereby requiring payment of LMP, where the supply curve is shaped such that small decreases in generation that is used to serve load will result in price decreases sufficient to offset the billing unit effect.

4. The Commission also required each RTO and ISO to review their current measurement and verification requirements in light of the changes in this Final Rule and develop appropriate revisions and modifications, if necessary, to ensure that their baselines remain accurate and that they can verify that demand response resources have performed.

5. Finally, the Final Rule set forth cost allocation requirements applicable to the costs incurred by RTOs and ISOs when paying demand response compensation. The Commission noted that, as a result of the billing unit effect, the difference between the amount owed by the RTO or ISO to both generation and demand response resources, and the revenue derived from load, results in a negative balance that must be addressed through cost allocation. Allocation of costs, as explained by the Final Rule, is reasonable when costs are allocated proportionally to all entities that purchase from the relevant energy market in the area(s) that benefit from the lower LMPs that result from demand response resource participation in the organized wholesale energy markets.

II. Requests for Rehearing and Clarification

6. The following entities have filed timely requests for rehearing of the Final Rule: Edison Electric Institute (EEI); Electric Power Supply Association (EPSA), Independent Power Producers of New York, Inc. (IPPNY), Electric Power Generation Association (EPGA), and New England Power Generators Association, Inc. (NEPGA) (collectively, Competitive Supplier Associations or CSA); EPSA, American Public Power Association (APPA), EPGA, and National Rural Electric Cooperative Association (NRECA) (collectively, Joint Petitioners); Midwest Transmission Dependent Utilities (Midwest TDUs); Organization of MISO States (OMS); PJM Power Providers Group (P3); and PPL Parties. The following entities have filed timely requests for clarification and/or rehearing of the Final Rule: California Department of Water Resources State Water Project (SWP); California Independent System Operator Corporation (CAISO);[3] Demand Response Supporters (DR Supporters);[4] Public Utilities Commission of the State of California (CPUC); Midwest ISO Transmission Owners (Midwest ISO TOs); and Old Dominion Electric Cooperative (ODEC), APPA, and NRECA (collectively, Joint

[3] California Independent System Operator Corporation (CAISO) requests that the Commission issue a substantive order within 30 days after the April 14, 2011 deadline for petitioners to file requests for rehearing. The Office of the Secretary issued an Order Granting Rehearing for Further Consideration on May 13, 2011. Accordingly, CAISO's issues are addressed in this order.

[4] Members of the Demand Response Supporters include: American Forest & Paper Association, Consumer Demand Response Initiative, EnerNOC, Inc., Project for Sustainable FERC Energy Policy, and Viridity Energy, Inc.

Parties). The Illinois Commerce Commission (ICC) filed a timely request for clarification.

7. Occidental Permian Ltd. and Occidental Chemical Corporation (collectively, Occidental), filed a motion for leave to answer and answer responding to the request for clarification or rehearing filed by the DR Supporters.[5] ISO New England Inc. (ISO-NE) and the New England Power Pool (NEPOOL) Participants Committee filed a motion for leave to answer and answer responding to the request for clarification filed by the ICC and the request for clarification or rehearing filed by the DR Supporters.[6] Viridity Energy, Inc. filed a motion for leave to answer and answer responding to the request for rehearing filed by EEI, the request for clarification or rehearing filed by the CPUC, and the request for clarification and rehearing filed by CAISO.[7] The Industrial Energy Consumer Group (IECG) filed a motion for leave to answer and answer to the motion for leave to answer and answer filed by ISO-NE.[8] The NEPOOL Participants Committee filed an answer responding to the motion for leave to answer and answer filed by IECG.[9] Wal-Mart Stores, Inc., along with a collection of retail end-use customer demand response participants, filed a letter supporting the Final Rule, and answering the request for clarification or rehearing

[5] Occidental Permian Ltd. and Occidental Chemical Corporation (Occidental) April 29, 2011 Answer.

[6] ISO New England Inc. (ISO-NE) April 29, 2011 Answer.

[7] Viridity Energy, Inc. (Viridity) May 6, 2011 Answer.

[8] Industrial Energy Consumer Group May 13, 2011 Answer.

[9] New England Power Pool (NEPOOL) Participants Committee May 24, 2011 Answer.

filed by the CPUC and the request for clarification and rehearing filed by CAISO.[10]

8. Rule 713(d)(1) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.713(d)(1) (2011), prohibits an answer to a request for rehearing. Accordingly, the answers from Occidental, ISO-NE and NEPOOL Participants Committee, Viridity, and Wal-Mart Stores, Inc. are rejected. IECG's and NEPOOL Participants Committee's answers to an answer are dismissed.

9. CAISO filed a motion to lodge, and an errata to that motion, seeking to include in the record a CAISO Market Surveillance Committee opinion regarding the Final Rule, as well as a concurring opinion by Steven Stoft of the Market Surveillance Committee, both issued on June 6, 2011, to supplement its request for clarification and rehearing.[11] CAISO notes that it included a draft of the opinion in its request for clarification and rehearing, indicating that it would supplement the filing with the final opinion once issued. CAISO indicated that it was unable to submit the final opinion with its request for clarification and rehearing because the Market Surveillance Committee procedures require draft opinions to be posted before they may be finalized.

10. We deny CAISO's motion to lodge. Although CAISO indicated in its request for clarification and rehearing that a final version of the Market Surveillance Committee opinion would be forthcoming, the draft submitted with the request for clarification and rehearing bears little resemblance

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[10] Wal-Mart Stores, Inc. June 8, 2011 Letter.

[11] CAISO June 22, 2011 Motion to Lodge.

to the final opinion submitted on June 22, 2011. The draft opinion included with the request for clarification and rehearing was two pages long. The final opinion submitted with the motion to lodge consists of 21 pages, and the Stoft opinion, which was not included with the request for clarification and rehearing, is an additional 24 pages. The CAISO filing does not respond to any arguments raised by other parties on rehearing, but rather adds supplemental material to its rehearing request, more than two months following the deadline for filing requests for rehearing. As such, we will reject it as an out-of-time rehearing request.[12]

III. Discussion

A. Commission Jurisdiction and Authority to Regulate Demand Response Resources

11. In the Final Rule, the Commission explained that it has jurisdiction over demand response in the organized wholesale energy markets due to the direct effect demand response resources have on wholesale energy prices.[13] The Commission stated that its actions in issuing the Final Rule arise out of its responsibility to ensure just, reasonable, and not unduly discriminatory or preferential wholesale energy market rates.[14] The Commission further noted that the Final Rule does not affect a state's authority over retail rates, nor does it preclude state-administered demand response programs.[15] Lastly, the Commission stated

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[12] *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,018, at P 19-21 (2011).

[13] Order No. 745, FERC Stats. & Regs. ¶ 31,322 at P 112.

[14] *Id*. P 115.

[15] *Id*. P 114.

that its actions are consistent with the policy set forth by Congress calling for the removal of barriers to demand response resource participation in the energy markets.[16]

1. Requests for Rehearing

12. Joint Petitioners, Midwest TDUs, PPL Parties, and P3 request rehearing arguing that the Commission does not have jurisdiction over the compensation paid to demand response providers.[17] The petitioners argue that demand response providers' actions, characterized by the petitioners as retail non-purchases, are not wholesale sales as described in section 201(b)(1) of the FPA.[18] The petitioners assert that because sections 205[19] and 206[20] of the FPA apply only to actions subject to the Commission's jurisdiction, the Commission is powerless to act on demand response compensation.[21] The petitioners analogize demand response services to non-jurisdictional retail rates applicable to retail purchases and conclude that demand response compensation falls within the realm of state jurisdiction.[22]

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[16] *Id*. P 113.

[17] Joint Petitioners Request for Rehearing at 7; Midwest TDUs Request for Rehearing at 8; PPL Parties Request for Rehearing at 7; P3 Request for Rehearing at 5-6.

[18] 16 U.S.C. § 824(b)(1) (2006).

[19] 16 U.S.C. § 824d.

[20] 16 U.S.C. § 824e.

[21] Joint Petitioners Request for Rehearing at 7; Midwest TDUs Request for Rehearing at 8; PPL Parties Request for Rehearing at 7-8; P3 Request for Rehearing at 5-6.

[22] Joint Petitioners Request for Rehearing at 7.

13. Joint Petitioners, Midwest TDUs, PPL Parties, and P3 assert that the Commission, by way of its order in *EnergyConnect, Inc.* (*EnergyConnect*),[23] has previously established that demand response providers are not engaged in a sale for resale of energy back into the energy market, and therefore are not subject to the Commission's jurisdiction because the terms of section 201(b)(1) are not met.[24]

14. Joint Petitioners, Midwest TDUs, PPL Parties, and P3 argue that the Commission is in error to the extent that it believes it has jurisdiction over demand response compensation through the "affecting" clause of sections 205(a) and 206(a) of the FPA.[25] The petitioners argue that Commission jurisdiction, obtained where certain rules and regulations affect rates or charges pertaining to the wholesale sale of electric energy, is not broad enough to overcome the fact that demand response is not a jurisdictional sale under section 201(b)(1) of the FPA.[26] As stated by the Joint Petitioners, the terms of sections 205(a) and 206(a) do not trump those of section 201(b)(1).[27]

15. Joint Petitioners request rehearing arguing that that Commission is prohibited from regulating

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[23] *EnergyConnect*, *Inc*., 130 FERC ¶ 61,031 (2010) (*Energy Connect*).

[24] Joint Petitioners Request for Rehearing at 6; Midwest TDUs Request for Rehearing at 9; PPL Parties Request for Rehearing at 7-8; P3 Request for Rehearing at 5.

[25] Joint Petitioners Request for Rehearing at 8-9; Midwest TDUs Request for Rehearing at 10-11; PPL Parties Request for Rehearing at 8; P3 Request for Rehearing at 5.

[26] Joint Petitioners Request for Rehearing at 9; Midwest TDUs Request for Rehearing at 10.

[27] Joint Petitioners Request for Rehearing at 9.

non-jurisdictional entities (demand response resources) through the exercise of its authority over public utilities (RTOs and ISOs).[28] The petitioners assert that the Commission is attempting to indirectly, and wrongly, exercise authority over demand response resources, entities it claims are non-jurisdictional under section 201(b)(1) of the FPA, by requiring RTOs and ISOs to pay demand response resources the LMP.[29] Joint Petitioners also assert that prior case law concerning Commission jurisdiction over capacity markets is unsupportive in the context of the Final Rule.[30] Joint Petitioners further argue that demand response resources, when offered into the organized wholesale energy market, have no greater effect on the rates generated by the market, than does the cost of cement, steel, or coal.[31] Petitioners' reasoning is that if the Commission were able to assert jurisdiction over demand response compensation in this manner, then it would also be able to do so with respect to any other non-jurisdictional factor that may affect rates.

16. Joint Petitioners also argue that that the Commission may not assert jurisdiction over demand response compensation even where demand response compensation is construed as a component of a jurisdictional, market-based rate for energy in organized markets.[32] Joint Petitioners assert that demand response does not qualify for Commission review even under a situation where the Commission may review

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[28] Joint Petitioners Request for Rehearing at 9.

[29] *Id.*

[30] *Id*. at 9-10.

[31] *Id*. at 11.

[32] *Id*. at 12.

a non-jurisdictional rate that is a component of a jurisdictional rate.

17. Petitioners assert that the Commission does not have implied jurisdiction over demand response compensation because "[demand response] is a retail non-purchase, and retail rates have traditionally been subject to State or local regulation."[33] The petitioners argue that courts are reluctant to infer jurisdiction in an agency over an area it seeks to regulate where the area to be regulated has traditionally been regulated by the states.[34]

18. Joint Petitioners and Midwest TDUs argue that the Commission erred in citing the Energy Policy Act of 2005 (EPAct 2005)[35] as support for its jurisdiction to regulate demand response compensation.[36] The petitioners argue that EPAct 2005 is a mere policy statement, and does not expand the Commission's jurisdiction or authority to implement that policy.[37]

19. Joint Petitioners, Midwest TDUs, CAISO, and CPUC argue that the Commission is interfering with existing retail demand response programs, and therefore is intruding on state jurisdiction.[38] Midwest TDUs argue that this constitutes a barrier, in the form

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[33] Joint Petitioners Request for Rehearing at 13.

[34] *Id.*

[35] Energy Policy Act of 2005, Pub. L. No. 109-58, § 1252(f), 119 Stat. 594, 965 (2005) (EPAct 2005).

[36] Joint Petitioners Request for Rehearing at 14; Midwest TDUs Request for Rehearing at 11-12.

[37] Joint Petitioners Request for Rehearing at 14; Midwest TDUs Request for Rehearing at 11-12.

[38] Joint Petitioners Request for Rehearing at 13; Midwest TDUs Request for Rehearing at 20-21; CAISO Request for Rehearing at 31-32; CPUC Request for Rehearing at 13-16.

of a financial disincentive, to participation in retail demand response programs.[39]

2. Commission Determination

20. We deny the requests for rehearing regarding the Commission's jurisdiction over demand response participation in organized wholesale energy markets. We continue to find that Commission regulation of demand response participation in the organized wholesale energy markets and the market rules governing that participation is essential to the Commission fulfilling its statutory responsibility to ensure that jurisdictional rates are just and reasonable.

21. Under section 201 of the FPA[40] the Commission has jurisdiction over the transmission of electric energy in interstate commerce, as well as the wholesale sale (or sale for resale) of electric energy in interstate commerce, and it has jurisdiction over all facilities used for such transmission or sale of electric energy. Section 201 also defines a public utility as "any person who owns or operates facilities subject to the jurisdiction of the Commission."[41] Sections 205[42] and 206[43] of the FPA provide the Commission with jurisdiction over all rates and charges made, demanded, or received by any public utility for or in connection with the transmission or sale of electric energy subject to the jurisdiction of the Commission. Those sections also provide the Commission with jurisdiction over all rules, regulations, practices, or

[39] Midwest TDUs Request for Rehearing at 20.

[40] 16 U.S.C. § 824.

[41] 16 U.S.C. § 824(e).

[42] 16 U.S.C. § 824d.

[43] 16 U.S.C. § 824e.

contracts that affect jurisdictional rates, charges, or classifications.

22. In *EnergyConnect*,[44] the Commission found that a company engaged solely in offering demand response services would not be a public utility and would not be making wholesale sales of electric energy. However, the Commission also found that it would still have jurisdiction to regulate certain aspects of demand response "as a practice that affects rates in organized wholesale electric markets under sections 205(a) and (c) and section 206(a) of the FPA."[45] In Order Nos. 719[46] and 719-A, the Commission reached the same conclusion, including with respect to its jurisdiction over demand response in RTO and ISO ancillary service markets. Speaking generally, the Commission found that within RTO and ISO markets, demand response "affects wholesale markets, rates, and practices."[47]

23. In support of this assertion of jurisdiction, the Commission in Order No. 719-A described a direct effect on wholesale prices caused by demand response participation in RTO and ISO markets.[48] The Commission stated that this direct effect occurs when demand response is offered directly into the wholesale market, causing a reduction in demand to

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[44] *EnergyConnect*, 130 FERC ¶ 61,031.

[45] *Id*. P 32.

[46] *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶ 31,281 (2008), *order on reh'g*, Order No. 719-A, FERC Stats. & Regs. ¶ 31,292 (2009), *order on reh'g*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

[47] Order No. 719-A, FERC Stats. & Regs. ¶ 31,292 at P 46.

[48] *Id.* P 47.

occur, thereby resulting in a lower wholesale price.[49] In addition, the Commission found that such demand response participation helps to mitigate generator market power and strengthen system reliability.[50] Demand response resources that participate in a wholesale market, especially when market prices are high, tend to lower the market clearing price placing downward pressure on generator offer strategies by making it more likely that a higher offer from a generator will not be accepted when the market clears.[51] Moreover, system reliability realizes a benefit because demand response generally can be dispatched by the system operator with a minimal notice period, helping to balance the electric system in the event that an unexpected contingency occurs.[52]

24. The Final Rule reiterated many of these findings in explaining the Commission's basis for jurisdiction with respect to demand response participation in organized wholesale energy markets.[53] We now reaffirm our previous findings on how demand response has a direct effect on wholesale rates subject to Commission jurisdiction under FPA section 201(b)(1), as well as our conclusion that these findings support Commission jurisdiction with respect to demand response participation in the organized

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[49] *Id.*

[50] *Id.*

[51] *Id.* In addition, demand response can reduce transmission rates by relieving congestion on transmission lines that leads to higher transmission charges. In RTO and ISO markets, these higher transmission charges are reflected in the congestion costs that wholesale customers are required to pay.

[52] Order No. 719-A, FERC Stats. & Regs. ¶ 31,292 at P 47.

[53] Order No. 745, FERC Stats. & Regs. ¶ 31,322 at P 112-15.

wholesale energy markets and the market rules governing that participation.[54]

25. This jurisdictional analysis is consistent with precedent in which the courts have found that the Commission has jurisdiction over aspects of RTO services that affect wholesale rates. For example, in *Connecticut Dep't of Pub. Util. Control v. FERC*,[55] petitioner challenged the Commission's authority to review, approve, or modify the Installed Capacity Requirement (ICR), a key input into ISO-NE's forward capacity market. Petitioner argued that any Commission-ordered increase in the ICR would be equivalent to the Commission directing the installation of new capacity, thereby violating the FPA's limit of Commission jurisdiction over generation facilities. The court rejected this argument, holding that the ICR is subject to the Commission's authority because it is a "practice affecting rates" under sections 205 and 206 of the FPA. Specifically, the court upheld the Commission's assertion of jurisdiction because it found that "[w]here capacity decisions about an interconnected bulk power system affect FERC-jurisdictional transmission rates for that system without directly implicating generation facilities, they come within the

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[54] The Commission's finding of this direct effect on wholesale rates is important in light of the statement of the U.S. Court of Appeals for the District of Columbia Circuit that the Commission is empowered under section 206 to assess practices that directly affect or are closely related to a public utility's rates and "not all those remote things beyond the rate structure that might in some sense indirectly or ultimately do so." *California Indep. Sys. Operator v. FERC*, 372 F.3d 395, 403 (D.C. Cir. 2004).

[55] *Connecticut Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477 (D.C. Cir. 2009) (*Connecticut*).

Commission's authority."[56] The court found that the ICR was not a direct regulation of generation, nor a requirement as to the amount of generation that had to be constructed.[57] Acknowledging that capacity is not electricity, the court nonetheless found that the Commission may "directly establish prices for capacity—or much the same, prices for failing to acquire enough capacity—even for the express purpose of incentivizing construction of new generation facilities."[58] These holdings reinforce well-established precedent with respect to Commission jurisdiction based on the "practice affecting rates" language of sections 205 and 206.[59] Similarly, if demand response participation in the organized wholesale energy market "help[s] to find the right price,"[60] as the

[56] *Connecticut*, 569 F.3d at 484.

[57] *Id*. at 483.

[58] *Id*. at 482.

[59] *See Groton v. FERC*, 587 F.2d 1296, 1302 (D.C. Cir. 1978) (capacity deficiency charge, just as the capacity adjustment charge "must be deemed to be within the Commission's jurisdiction because it too represents a charge for the power and service the overloaded participant receives or it is at least a rule or practice affecting the charge for these services"); *Mississippi Industries v. FERC*, 808 F.2d 1525, 1542 (D.C. Cir. 1987) (while capacity allocation costs "do not fix wholesale rates, their terms do directly and significantly affect the wholesale rates at which the operating companies exchange energy"); *Maine Pub. Utils. Comm'n v. FERC*, 520 F.3d 464, 479 (D.C. Cir. 2008), *rev'd in part sub nom*. *NRG Power Marketing, LLC v. Me. Pub. Utils. Comm'n*, 130 S. Ct. 693 (2010), *remanded*, *Me. Pub. Utils. Comm'n v. FERC*, 625 F.3d 754 (D.C. Cir. 2010) (concluding that the Commission had jurisdiction over capacity markets, because the "the protracted litigation over Must-Run agreements, the locational installed capacity market, and the Forward Market is fundamentally a dispute over the rates that will be paid to suppliers of capacity.").

[60] *Connecticut*, 569 F.3d at 485.

Commission has found repeatedly, then that demand response participation and the corresponding RTO and ISO market rules "would still amount to a 'practice . . . affecting' rates."[61]

26. Joint Petitioners contend that the capacity market cases are not controlling because capacity markets are subject to Commission jurisdiction under section 201 of the FPA even though capacity itself is not mentioned. The Commission rejects this argument. Joint Petitioners fail to support their contention that some practices that directly affect jurisdictional rates but are not mentioned in section 201 (e.g., market rules with respect to capacity) are subject to the Commission's jurisdiction, while other such practices affecting rates (e.g., market rules with respect to demand response participation in an organized wholesale energy market) are not. As discussed above, the Commission finds court precedent on capacity markets and the "practice affecting rates" language of sections 205 and 206 to be analogous to the issues presented here with respect to demand response participation in organized wholesale energy markets and the market rules of the various ISOs and RTOs that govern that participation.

27. Joint Petitioners, Midwest TDUs, PPL Parties, and P3 argue that section 201(b) of the FPA does not invest the Commission with jurisdiction over demand response compensation because demand response providers are not public utilities. In making this argument, petitioners rely on the Commission's

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[61] *Id*. The court in *Connecticut*, in fact, observed that one of the methods of responding to the incentives produced by increases in the ICR short of building new generation facilities included the use of "demand response contracts where users are compensated for committing to use less electricity during shortages." *Id*. at 482.

findings in *EnergyConnect*. Joint Petitioners, Midwest TDUs, PPL Parties, and P3 argue that the Commission cannot claim jurisdiction over demand response resources through section 205's and 206's "affecting" clause when section 201(b) has not been satisfied. The Commission rejects these arguments. The Commission's findings that demand response does not involve a wholesale sale of energy, and that entities engaged solely in demand response are not public utilities, do not void the Commission's jurisdiction with respect to demand response participation in organized wholesale energy markets and the market rules of various RTOs and ISOs that govern that participation. As noted above, the Commission discussed this issue, as well as the Commission's jurisdictional conclusion with respect to the "practice affecting rates" language of sections 205 and 206, in detail in *EnergyConnect*.[62] A demand response resource that, as discussed in *EnergyConnect*, may not be a public utility, nonetheless may choose to participate in the RTO- and ISO-administered organized wholesale energy markets, therefore making it a market participant. The Commission has repeatedly found that market rules governing such participation by demand response resources in an organized wholesale energy market are a practice that directly affects rates in those jurisdictional markets.[63] The rules regarding compensation required by the Final Rule are one example of those market rules. Much as the forward

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[62] *EnergyConnect*, 130 FERC ¶ 61,031.

[63] As discussed above, the courts have recognized the breadth of the Commission's jurisdiction under sections 205 and 206 of the FPA. *See Connecticut*, 569 F.3d at 484-85; *City of Cleveland v. FERC*, 773 F.2d 1368, 1376 (D.C. Cir. 1985) ("there is an infinitude of practices affecting rates and service").

capacity markets at issue in the court cases discussed above determine rates to be paid to capacity resources, the organized wholesale energy markets determine the rates (market-clearing prices) that are paid to participants in those markets.

28. It is also relevant that in *Sacramento Municipal Utility District v. FERC*,[64] the court affirmed the Commission's jurisdiction to impose marginal line losses on a non-public utility. In that case, a non-public utility argued that by approving CAISO's assessment of marginal loss charges to transactions involving the non-public utility's use of transmission ownership rights, the Commission unlawfully dictated rates, terms or conditions of service to a non-public utility's use of its own transmission facilities and effectively compelled such entity to transfer control over its transmission facilities to the CAISO. The court found, to the contrary, that the charges assessed to the non-public utility involved nothing more than charges for using the CAISO's facilities. The court concluded that the Commission did not exceed its jurisdiction:

> Far from compelling Imperial to become a participating transmission owner of [CAISO], FERC merely permitted the ISO to charge Imperial for the costs incurred by the ISO when Imperial conducts transactions that cause transmission losses on the ISO's grid. The Commission's proper exercise of its power to regulate [CAISO's] rates was not transformed into a violation of its statutory jurisdiction by dint of its incidental effect on Imperial.[65]

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[64] *Sacramento Mun. Util. Dist. v. FERC*, 616 F.3d 520 (D.C. Cir. 2010).

[65] *Id*. at 536. *See also Transmission Agency of N. Cal. v. FERC*, 628 F.3d 538, 540 (D.C. Cir. 2010) (TANC) (finding Commission

In *United Distribution Companies v. FERC*,[66] the court likewise affirmed the Commission's jurisdiction to regulate resales of natural gas transportation capacity by non-jurisdictional entities.[67] The court concluded that the Commission had jurisdiction because the "the transaction itself controls access to interstate transportation capacity, entirely independent of the jurisdictional nature of the releasing and replacement shippers."[68] Similarly, the Commission has jurisdiction over the way in which RTOs and ISOs operate jurisdictional markets, including the market rules

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jurisdiction to regulate interconnections with non-public utilities when these transactions "impact the CAISO-controlled grid [and] only a party that chooses to use the CAISO-controlled grid is affected").

[66] *United Distribution Cos. v. FERC*, 88 F.3d 1105, 1151-1154 (D.C. Cir. 1996).

[67] *Id.*

[68] *Id.* at 1153. We also note the statement of the U.S. Supreme Court in *Colorado Interstate Gas Co. v. FPC*, 324 U.S. 581, 602-03 (1945), in interpreting a similar jurisdictional limitation in § 1(b) of the Natural Gas Act with respect to gathering:

> That does not mean that the part of § 1(b) which provides that the Act shall not apply "to the production or gathering of natural gas" is given no meaning. Certainly that provision precludes the Commission from any control over the activity of producing or gathering natural gas. . . We only decide that it does not preclude the Commission from reflecting the production and gathering facilities of a natural gas company in the rate base and determining the expenses incident thereto for the purposes of determining the reasonableness of rates subject to its jurisdiction.

See also Northern Natural Gas Co. v. FERC, 929 F.2d 1261, 1269 (8th Cir. 1991) (finding that *Colorado Interstate* also permits the Commission to directly regulate rates for transportation over a pipeline's own gathering facilities performed in connection with admittedly jurisdictional interstate transportation).

that govern demand response participation in those markets, to assure that the rates resulting from those markets are just and reasonable.

29. Joint Petitioners argue that demand response resources, when offered into the organized wholesale energy market, have no greater effect on the rates generated by the market than does the cost of cement, steel, or coal. Petitioners express concern that if the Commission may assert jurisdiction over demand response compensation, then it would also be able to do the same with respect to any other factor that may affect rates.

30. We disagree with Joint Petitioners' argument and find that demand response resources are not similar to an input cost for generation. A properly functioning market should reflect both the willingness of sellers to sell at a price and the willingness of buyers to purchase at a price. In an RTO- or ISO-run market, however, buyers are generally unable to directly express their willingness to pay for a product at the price offered. As discussed later, RTOs and ISOs cannot isolate individual buyers' willingness to pay which results in extremely inelastic demand. Including demand response as a resource in RTO and ISO markets provides a way for buyers to indicate the price at which they are willing to stop consumption.

31. We recognize that merely because an input to generation may affect a wholesale rate, our jurisdiction does not extend to the regulation of the input itself. Demand response resources that participate in an RTO- or ISO-administrated organized wholesale energy market, however, are not merely an input cost for generation that indirectly affects wholesale rates. Rather, in the circumstances covered by the Final

Rule, demand response resources are direct participants in the organized wholesale energy markets over which we have jurisdiction (just as is generation), and that participation has a direct and substantial effect on rates in those markets.[69] In light of this distinction, we disagree with Joint Petitioners' claim that the Commission's actions in the Final Rule create a slippery slope that will lead to limitless Commission jurisdiction. As discussed above, the Commission's statutory authority extends to those rules, regulations, practices, or contracts that directly affect the jurisdictional rates charged by public utilities.

32. Joint Petitioners, Midwest TDUs, CAISO, and CPUC argue that the Commission is interfering with existing retail demand response programs and, therefore, is intruding on state jurisdiction. The Commission rejects this argument. As the Commission stated in the Final Rule, demand response is a complex matter that lies at the confluence of state and federal jurisdiction.[70] Respecting that state interest, the Commission made clear in the Final Rule that we are not intruding into the province of state regulation and are "not regulating retail rates or usurping or impeding state regulatory efforts concerning demand response."[71] The fact that participation in a Commission-jurisdictional RTO or ISO market may indirectly affect incentives in a state demand response initiative does not deprive the Commission of the

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[69] *See Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277, 1282 (D.C. Cir. 2007) (affirming Commission's assertion of jurisdiction over interconnections with dual-use facilities, when the facilities are included in a jurisdictional rate and the transaction facilitates a wholesale sale of electric energy).

[70] Order No. 745, FERC Stats. & Regs. ¶ 31,322 at P 114.

[71] *Id.*

ability to act within the jurisdictional boundaries discussed above.

33. Joint Petitioners and Midwest TDUs claim that the Commission cannot rely on section 1252(f) of EPAct 2005[72] as a basis for its jurisdiction to regulate demand response compensation. Petitioners base their argument on *Comcast Corp. v. FCC*,[73] asserting that this statutory language is a mere policy statement and does not expand the Commission's jurisdiction or authority to implement policy.

34. Neither the Final Rule nor this order relies on section 1252(f) of EPAct 2005 as an independent basis for Commission jurisdiction. The court in *Comcast* recognized that while statements of Congressional policy do not establish jurisdiction, "statements of congressional policy can help delineate the contours of statutory authority."[74] To that end, we cited section 1252(f) of EPAct 2005 because it sheds light on the contours of the Commission's statutory authority. Section 1252(f) of EPAct 2005 states that it is the policy of the United States that unnecessary barriers to demand response participation in energy, capacity, and ancillary services markets shall be eliminated. No commenter in this proceeding questions that such markets, including the organized wholesale energy markets addressed in the Final Rule, are subject to the Commission's jurisdiction.

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[72] EPAct 2005, Pub. L. No. 109-58, § 1252(f), 119 Stat. 594, 965 ("It is the policy of the United States that . . . unnecessary barriers to demand response participation in energy, capacity, and ancillary service markets shall be eliminated.").

[73] *Comcast Corp. v. FCC*, 600 F.3d 642 (D.C. Cir. 2010) (*Comcast*).

[74] *Comcast*, 600 F.3d at 654.

35. In light of the Commission's jurisdiction, under section 201 of the FPA, over rates established in the organized wholesale energy markets, and for the reasons discussed in detail above, the Commission concludes that demand response participation in the organized wholesale energy markets and the market rules governing that participation are "practices affecting rates" pursuant to sections 205 and 206 of the FPA.

B. Demand Response Resource Compensation Level

36. Separate from its findings as to the basis for Commission jurisdiction with respect to demand response participation in the organized wholesale energy markets and the market rules governing that participation, the Final Rule requires that each RTO and ISO that has a tariff provision permitting demand response resources to participate as a resource in the energy market must pay to those demand response resources the market price when the demand response resource has the capability to balance supply and demand and when payment is cost-effective. The Commission found that LMP is the appropriate compensation level because LMP reflects the marginal value of the demand response resource to each RTO and ISO. The Commission explained that the market-clearing LMP is the appropriate compensation level where demand response resources are a cost-effective alternative to generation for balancing the energy market.[75]

1. Requests for Rehearing

[75] Order No. 745, FERC Stats. & Regs. ¶ 31,322 at P 47.

37. ICC requests clarification that the Commission is basing the comparability of demand response resources and generation resources on the competition of the two resources in the dispatch model, i.e., as they are used to balance electricity supply and demand in the economic dispatch and not based on economic comparability. ICC argues that demand response is not comparable to generation in terms of the aggregate economic impact, financial settlement, and incentives associated with compensation paid at LMP. ICC expresses concern that LMP compensation will cause demand response providers to disengage from economic production, whereas generation resources do not have the same incentive.[76]

38. CSA, P3, and PPL Parties request rehearing arguing that demand response resources are not equivalent to generation in terms of physical characteristics, marginal value, planning, economics, performance requirements, operational security, penalties, and reliability services. CSA further argues that a demand response resource is not a resource like generation because it cannot power residences, commercial establishments or industrial facilities, and LMP payment to demand response resources, unlike LMP payment to generation, causes the RTO or ISO to incur a net loss.

39. Joint Parties request rehearing and clarification arguing that demand response resources and generation resources are not comparable, even for the purpose of balancing supply and demand, because

[76] Illinois Commerce Commission (ICC) Request for Rehearing at 5.

demand response resources have less stringent performance requirements and do not have as a part of their core business the generation of electricity.

40. CSA, EEI, Midwest TDUs, Joint Parties, Organization of MISO States, PPL Parties, and P3 argue that the Final Rule conflicts with Commission efforts to promote competitive markets because, according to these petitioners, compensating demand response at LMP is a subsidy, or overcompensation, resulting in the suppression of LMPs in the energy market.[77]

41. Petitioners explain that the suppression of LMPs will distort price signals, causing customers to reduce or increase their energy purchases at other than optimal levels.[78] CSA further asserts that a suppression of the LMP will delay the construction of new generation while accelerating the retirement of current facilities.[79]

42. CSA further argues that the Final Rule is a violation of a regulated utility's right to just and reasonable compensation for jurisdictional wholesale

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[77] Competitive Power Supplier Associations (CSA) Request for Rehearing at 16, 40; Edison Electric Institute (EEI) Request for Rehearing at 13; Midwest Transmission Dependent Utilities (Midwest TDUs) Request for Rehearing at 15; American Public Power Association, National Rural Electric Cooperative Association, and Old Dominion Electric Cooperative (collectively, Joint Parties) Request for Rehearing at 18; Organization of MISO States (OMS) Request for Rehearing at 4; PPL Parties Request for Rehearing at 20; PJM Power Providers Group (P3) Request for Rehearing at 8.

[78] *See, e.g.*, CSA Request for Rehearing at 44; EEI Request for Rehearing at 13.

[79] CSA Request for Rehearing at 43.

sales.[80] CSA states that the Commission failed to quantify or identify the amount by which jurisdictional rates are excessive, or would be excessive, absent the Final Rule.[81] CSA asserts that the Commission has improperly assumed that an increase in demand response resource participation leading to a lower market price for energy is "always better"[82] without regard to whether the corresponding lower rate and reduced revenue for regulated entities will be compensatory or confiscatory. CSA asserts that the Commission, by mandating compensation at LMP, has violated the Takings Clause of the Fifth Amendment of the U.S. Constitution and failed to satisfy its duty under the FPA to ensure that rates for jurisdictional sales are just and reasonable as to jurisdictional public utilities making those sales.[83]

43. Petitioners rely on Dr. Hogan and others in support of their position that paying LMP is overcompensation.[84] EEI refers to Dr. Hogan's argument that a compensation payment of LMP causes a demand response resource to receive a double payment for its curtailment. Dr. Hogan contends that a double payment results from the fact that the demand response resource does not pay for the energy that it would have consumed and also receives full LMP compensation from the RTO or ISO for its curtailment. Likewise, EEI and Midwest TDUs cite

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[80] CSA Request for Rehearing at 51 (citing *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 607 (1944)).

[81] *Id*. at 49.

[82] *Id*. at 49-50.

[83] *Id*. at 50.

[84] EEI Request for Rehearing at 13-15; Joint Parties Request for Rehearing at 18; Midwest TDUs Request for Rehearing at 11.

Potomac Economics, Ltd. for the position that the Final Rule allows "[demand response] resource[s] to sell energy in the wholesale market that it is not required to purchase at the retail rate. Hence, one can clearly see in this case that the [demand response] resource is receiving a subsidy to curtail equal to the retail rate. This will manifest itself in potentially significant economic inefficiencies."[85]

44. EEI argues that large industrial or commercial customers that use behind-the-meter generation to satisfy their energy needs can receive compensation in the amount of two times the LMP.[86] Large industrial customers with behind-the-meter generation that purchase their energy requirements at the LMP set in the relevant RTO or ISO energy markets have the option to self-supply when it is less expensive to do so.[87] EEI and CSA argue that customers with behind-the-meter generation that reduce their load on the grid and are paid LMP as a result actually realize a payment of twice the LMP because they also avoided purchasing the energy.[88] EEI states that in essence, the customer is a generator that is now directly competing with other wholesale generators.[89]

45. CSA, EEI, and Joint Parties state that the Commission is erroneously relying on a presumption that compensation at LMP is the correct payment

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[85] EEI Request for Rehearing at 14; *see also* Midwest TDUs Request for Rehearing at 11.

[86] EEI Request for Rehearing at 21.

[87] *Id*.

[88] EEI Request for Rehearing at 21; CSA Request for Rehearing at 24 n.80.

[89] EEI Request for Rehearing at 21.

level.[90] CSA argues that the Final Rule relies on a number of faulty assumptions and policy judgments including: (1) current levels of demand response participation are inadequate; (2) current levels of compensation paid to demand response resources are inadequate; (3) paying LMP will mitigate barriers to entry faced by demand response resources; (4) the "required subsidy" should be equal to the avoided costs of retail purchases; and (5) standardization of demand response compensation is the only solution available.[91]

46. CSA, EEI, Midwest TDUs, Joint Parties, OMS and PPL Parties argue that paying LMP-G is the appropriate payment level because it accounts for the avoided cost that the retail customer retains by curtailing its consumption.[92] Stated another way, EEI argues that a retail customer actually has a property right to consume energy, and that it is this property right, or call option, that it is selling to the RTO or ISO.[93] EEI states that the RTO or ISO should be required to pay for the market value of the call option, rather than the market value of the foregone energy.[94]

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[90] CSA Request for Rehearing at 28; EEI Request for Rehearing at 11; Joint Parties Request for Rehearing at 11.

[91] CSA Request for Rehearing at 30.

[92] CSA Request for Rehearing at 77-78; EEI Request for Rehearing at 11; Midwest TDUs Request for Rehearing at 18; Joint Parties Request for Rehearing at 17; OMS Request for Rehearing at 4; PPL Parties Request for Rehearing at 19; P3 Request for Rehearing at 14.

[93] EEI Request for Rehearing at 11.

[94] *Id*. at 12.

47. Midwest ISO TOs and Joint Parties request rehearing arguing that the Commission erred in stating that factoring retail rates into wholesale compensation payments presents problems for state public utility commissions, ISOs, and RTOs.[95] Petitioners point out that several state public utility commissions, ISOs, and RTOs filed comments explaining that a methodology that properly accounts for "G" (generation) does not impose an administrative burden on the RTOs and ISOs, and does not improperly impact state public utility commissions. Petitioners further assert that the Commission's observation that RTOs and ISOs do not subtract a cost component from the compensation paid to generators misses their point, because, while RTOs and ISOs pay generators full LMP, generators do in fact incur production costs that result in a reduced net compensation amount; in contrast they argue that demand response resources pay nothing for the "call option" associated with retail energy not consumed.[96]

48. CSA, EEI, Midwest ISO TOs, and Joint Parties request rehearing arguing that the Final Rule does not establish a rational connection between the perceived problem and the Commission's solution. Petitioners argue that the Final Rule does not explain how the barriers to entry that demand response resources face with respect to organized wholesale energy markets

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[95] Midwest ISO Transmission Owners (Midwest ISO TOs) Request for Rehearing at 20-21; Joint Parties Request for Rehearing at 18.

[96] Midwest ISO TOs Request for Rehearing at 21.

will be mitigated or resolved by requiring RTOs and ISOs to pay demand response resources the LMP.[97]

49. CSA and EEI request rehearing arguing that the Final Rule will have the opposite of its intended effect because it will hinder the development of retail dynamic price responsive demand programs, along with other state reforms.[98] Their argument relies on the notion that paying LMP compensation is a subsidy that will inappropriately encourage demand response resource participation in wholesale, rather than retail, programs.

50. CSA, EEI, Midwest TDUs, Midwest ISO TOs, Joint Parties, PPL Parties, P3, and CAISO further assert that the Commission failed to address, or dismissed entirely, arguments opposing the LMP compensation level.[99] Petitioners emphasize arguments in favor of LMP-G and a region-by-region approach. Petitioners assert that the Commission fails to distinguish the standardization in the Final Rule from the region-by-region approach permitted by the Commission in Order No. 719.[100]

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[97] CSA Request for Rehearing at 28; EEI Request for Rehearing at 17-18; Midwest ISO TOs Request for Rehearing at 19; Joint Parties Request for Rehearing at 12-13.

[98] CSA Request for Rehearing at 46-47; EEI Request for Rehearing at 20.

[99] CSA Request for Rehearing at 25-26; EEI Request for Rehearing at 8-9; Midwest TDUs Request for Rehearing at 6; Midwest ISO TOs Request for Rehearing at 10; Joint Parties Request for Rehearing at 7; PPL Parties Request for Rehearing at 10; P3 Request for Rehearing at 7; CAISO Request for Rehearing at 48-49.

[100] Petitioners argue that Order No. 719 specifically directed RTOs and ISOs to develop technical requirements, tailored to their individual circumstances, to facilitate the participation of

51. CSA requests rehearing arguing that the Final Rule makes the erroneous and unsupported suggestion that LMP compensation is needed because current RTO and ISO market power mitigation rules are inadequate.[101] Petitioners argue that the Commission failed to engage in reasoned decision-making and cast doubt on RTO and ISO market rules that the Commission previously approved. Petitioners claim that paying LMP compensation will lead to a case of over-mitigation because energy markets will now be subject to both existing market manipulation rules and demand response resource participation resulting in suppressed LMPs. Petitioners state that the Commission's previous approvals of supplier market power rules were made without reference to the level of demand response participation in the market, thus demonstrating that demand response is not necessary to maintain fair and competitive markets.

52. Joint Petitioners, Midwest TDUs, PPL Parties, EEI, and P3 argue that the Commission failed to make a reasoned finding, as required by section 206 of the FPA, that the existing demand response compensation paid by RTOs and ISOs, on a region-by-region basis, is unjust and unreasonable.[102]

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demand response resources in the ancillary services market. *See, e.g.*, CSA Request for Rehearing at 73 (citing Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 50, 59).

[101] CSA Request for Rehearing at 54.

[102] Electric Power Supply Association, American Public Power Association, Electric Power Generation Association, and National Rural Electric Cooperative Association (collectively, Joint Petitioners) Request for Rehearing at 8; Midwest TDUs Request for Rehearing at 11; PPL Parties Request for Rehearing at 11;

53. CSA requests rehearing based on Dr. Hogan's testimony, arguing that the Final Rule will facilitate or mandate the exercise of buyer market power, including a buyers' cartel, which will lead to artificially-suppressed prices.[103] Petitioners assert that the Final Rule will facilitate buyer market power, artificially reducing prices below competitive levels.

2. Commission Determination

a. LMP Compensation

54. The Commission denies the requests for rehearing and affirms its finding that LMP is the appropriate compensation level for demand response resources for service provided in the organized wholesale energy markets when these resources have the capability to balance supply and demand as an alternative to generation and when dispatch of demand response is cost-effective as determined by the net-benefits test described in the Final Rule. The Commission continues to find, as explained in the Final Rule, that LMP is the appropriate compensation level when the aforementioned two conditions are satisfied because LMP reflects the marginal value of demand response resources and generation resources to each RTO and ISO.[104] The rehearing requests generally reiterate arguments that were considered in the Final Rule and, for the reasons stated therein, are rejected here.

55. As the requests for rehearing indicate, there continue to be diverging opinions, including among

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EEI Request for Rehearing at 7; P3 Request for Rehearing at 12-13.

[103] CSA Request for Rehearing at 57-58.

[104] Order No. 745, FERC Stats. & Regs. ¶ 31,322 at P 47.

noted experts, regarding the appropriate level of compensation for demand response resources participating in the organized wholesale energy markets. In the face of diverging opinions, the Commission in the Final Rule observed that, as the courts have recognized, "issues of rate design are fairly technical and, insofar as they are not technical, involve policy judgments that lie at the core of the regulatory mission."[105] The Commission also observed that, in making such judgments, it takes into account both the economic analysis of the markets subject to our jurisdiction, and the practical realities of how those markets operate.[106] With this framework in mind, the Commission on balance agreed with commenters that supported payment of LMP under conditions when it is cost-effective to do so, as determined by the net benefits test described in the Final Rule.

56. Petitioners argue on rehearing that demand response is not comparable to generation and contend that a number of differences justify paying demand response resources a different price than the market clearing price. We disagree. As the Commission explained in the Final Rule, a power system must be operated so that there is real-time balance of generation and load, supply and demand. When balancing supply and demand, an RTO or ISO therefore can rely on the dispatch of a generation resource to increase supply or a demand response

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[105] *Id*. P 46 (citing *Elec. Consumer Res. Council v. FERC*, 407 F.3d 1232, 1236 (D.C. Cir. 2005); *Town of Norwood v. FERC*, 962 F.2d 20, 22 (D.C. Cir. 1992)).

[106] *Id*. (citing *Elizabethtown Gas Co. v. FERC*, 10 F.3d 866, 872 (D.C. Cir. 1993); *Vermont Dep't of Pub. Serv. v. FERC*, 817 F.2d 127, 135 (D.C. Cir. 1987); *Columbia Gas Transmission Corp. v. FERC*, 750 F.2d 105, 112 (D.C. Cir. 1984)).

resource to decrease demand.[107] Petitioners nonetheless argue that demand response resources are not physically comparable to generation because they do not produce electricity and cannot serve load. While we agree that demand response resources do not create electricity that can be used to serve load, that fact is not dispositive here. The electric industry requires near instantaneous balancing of supply and demand at all times to maintain reliability, and it is in that context that the Commission found that demand response can balance supply and demand as can generation when dispatched in the organized wholesale energy markets.[108] Because the balancing of generation and load when clearing the RTO and ISO day-ahead and real-time energy markets can be accomplished by changes in either supply or demand, demand response resources that clear in the day-ahead and real-time energy market should receive the same market-clearing LMP as compensation in the organized wholesale energy markets when those resources meet the conditions established in the Final Rule as a cost-effective alternative to the next highest-bid generation resources for purposes of balancing the energy market.[109]

57. Petitioners also argue that demand response and generation do not have the same marginal value because demand response has less stringent performance requirements. In Order No. 719, the Commission refrained from assigning a strict definition to comparability; nevertheless, the Commission required that demand response resources be: (1)

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[107] *Id*. P 49.

[108] *Id*. P 56.

[109] Order No. 745, FERC Stats. & Regs. ¶ 31,322 at P 54.

"technically capable of providing the ancillary service and meet the necessary technical requirements; and (2) submit a bid under the generally-applicable bidding rules . . ."[110] Thus the Commission linked comparability to the technical capability of a demand response resource to provide a particular service, not to whether the performance requirements of a demand response resource are identical to a generation resource. While demand response and generation may not be identical resources in every respect, both types of resources are equally able to assist RTOs and ISOs in maintaining a balance between supply and demand when they meet an RTO's or ISO's requirements to deliver their product or service when and where needed on the margin. Commenters have not demonstrated that the differences between generation and demand response render one superior to the other for purposes of balancing the system.

58. Petitioners further argue that the Final Rule's requirement to pay LMP compensation is a subsidy, double payment, or overcompensation, provided to demand response resources. Petitioners contend that paying LMP, rather than LMP-G, leads to distorted price signals and thus causes some customers to reduce energy usage to below-optimal levels, or others to increase usage to above-optimal levels. In the Final Rule, the Commission rejected these arguments and explained that demand response resources participating in the organized wholesale energy markets can be cost-effective, as determined by the net benefits test described therein, for balancing supply and demand and, in those circumstances, it follows that the

[110] Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 47.

demand response resource should also receive compensation at LMP.[111] Moreover, petitioners' arguments fail to acknowledge the market imperfections caused by the existing barriers to demand response discussed in the Final Rule and again below. In Order No. 719, the Commission found that allowing demand response to bid into organized wholesale energy markets "expands the amount of resources available to the market, increases competition, helps reduce prices to consumers and enhances reliability."[112] Moreover, as Dr. Kahn noted in this proceeding, paying demand response LMP sets "up an arrangement that treats proffered reductions in demand on a competitive par with positive supplies; but the one is no more a [case of overcompensation] than the other: the one delivers electric power to users at marginal costs—the other—reductions in costs—both at competitively determined levels."[113]

59. Petitioners challenge the Commission's consideration of market imperfections caused by existing barriers to demand response as relevant to the level of appropriate compensation for demand response resources participating in the organized wholesale energy markets. We continue to find that the barriers to demand participation in the wholesale market, such as the lack of a direct connection between wholesale and retail prices, lack of dynamic retail prices (retail prices that vary with changes in marginal wholesale costs), lack of real-time information sharing, and the

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[111] Order No. 745, FERC Stats. & Regs. ¶ 31,322 at P 61.

[112] *Id*. (citing Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 154).

[113] *Id*. (citing DR Supporters August 30, 2010 Reply Comments (Kahn Affidavit at 9-10)).

relative lack of sufficient retail metering technology,[114] demonstrate that customers do not have the ability to respond to the often volatile price changes in the wholesale market and demonstrate the need for including demand response as part of wholesale market design. If the price responsiveness of demand is not fully reflected in the wholesale market, the price, a fortiori, will be higher than it would be in a competitive market.[115] To establish just and reasonable prices under such circumstances, we find that the demand response that can participate in the wholesale market should be paid the marginal value of its contribution.

60. Some petitioners argue that the Commission improperly relied on a finding that insufficient demand response resources exist as a justification for paying LMP. The Final Rule was not based on a predetermined assessment of the amount of demand response that is necessary in the market. Rather, given the barriers that clearly exist to full participation of demand in the wholesale market, the Commission determined that payment of LMP is appropriate as it represents the value of the contribution of demand to the market during those periods in which demand response provides net benefits.

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[114] *Id*. P 57. *See also* Monitoring Analytics, The Independent Market Monitor for PJM, Comments, Docket No. RM10-17-000, at 4-6 (filed May 13, 2010); Monitoring Analytics, Barriers to Demand Side Response in PJM, Docket No. ER09-1063-000 (filed July 1, 2009); Federal Energy Regulatory Commission Staff, A National Assessment of Demand Response Potential (June 2009), found at http://www.ferc.gov/legal/staff-reports/06-09-demand-response.pdf).

[115] Order No. 745, FERC Stats. & Regs. ¶ 31,322 at P 59.

61. The Commission similarly rejects arguments made by CSA, EEI, Midwest ISO TOs, and Joint Parties stating that the Commission failed to explain how paying compensation at LMP will help reduce barriers. As indicated above, the existence of barriers helps to explain why payment of LMP as the market value of demand response services helps to produce just and reasonable wholesale energy prices. Paying LMP to demand resources will help address the lack of a direct connection between wholesale and retail prices and the lack of dynamic retail prices by providing those customers that can respond to price signals with the accurate market price signal for such response. Paying LMP, the marginal cost of energy, when demand response is a capable alternative to a generation resource, also will encourage more demand-side participation. As stated in the Final Rule, more demand-side participation will cause wholesale and retail prices to converge on a price level reflecting demand's ability to respond to the marginal cost of energy.[116]

62. Lack of real-time information sharing and a lack of incentives to invest in enabling technologies can be addressed by making additional investment resources available to market participants.[117] Paying the full marginal value of energy to demand response will provide the proper level of investment resources available for capital improvements.

63. The Commission acknowledged that noted experts differed on whether paying LMP in the current circumstances facing the wholesale electric market is a reasonable price. In determining that LMP is the

[116] *Id.*

[117] *Id.* P 57 (quoting EnerNOC May 13, 2010 Comments at 4).

just and reasonable price to pay for demand response, the Commission examined some of the previously recognized barriers to demand response that exist in current wholesale markets. These barriers create an inelastic demand curve in the wholesale energy market that results in higher wholesale prices than would be observed if the demand side of the market were fully developed. The Commission found that paying LMP when cost-effective may help remove these barriers to entry of potential demand response resources, and, thereby, help move prices closer to the levels that would result if all demand could respond to the marginal price of energy.[118] Furthermore, the Commission found that since LMP reflects the marginal value of the demand response resource to the RTO or ISO, it is a just and reasonable rate to be paid to demand response resources. RTOs and ISOs already pay LMP compensation to generation resources because LMP represents their marginal value.[119] Thus, demand response resources, where capable of balancing supply and demand as an alternative to generation and when dispatch of demand response resources is cost-effective, also should be compensated for the marginal value they provide. The Commission recognized that in some circumstances paying the LMP to demand response would not be cost-effective and therefore determined that payment of LMP in conjunction with a net benefits test will ensure a just and reasonable rate by

[118] *Id.* P 57-59 (recognizing factors unique to the electric industry, including the need for instantaneous balancing of supply and demand and that demand responsiveness to price changes is relatively inelastic).

[119] *See* DR Supporters August 30, 2010 Reply Comments (Kahn Affidavit at 2).

resulting in the cost-effective dispatch of demand response resources.

64. Dr. Kahn took note of these considerations in supporting the payment of LMP without reduction:

> These circumstances—specifically, the fact that pass-through of the LMP is costly and (perhaps) politically infeasible, the possibly prohibitive cost of the metering necessary to charge each ultimate user, moment-by-moment, the often dramatic changes in true marginal costs for each—can justify direct payment at full LMP to distributors and ultimate customers who promise to guarantee their immediate response to such increases in true marginal costs of supplying them.[120]

Many of those seeking rehearing maintain that the only correct price to be paid load must reflect the savings load realizes from not having to purchase electricity. However, as the Commission found in the Final Rule, in circumstances in which the net benefits test is satisfied, paying LMP to demand response resources does not reflect a double payment; indeed, where cost effective, demand response resources should be paid the same price received by generation.[121]

65. Moreover, the Commission pointed out, examining cost avoidance by demand response resources is not consistent with the treatment of generation. In the absence of market power concerns, the Commission generally does not examine each of the costs of production for individual resources participating as supply resources in the organized wholesale electricity

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[120] DR Supporters September 16, 2009 Comments filed in Docket No. EL-09-68-000 (Kahn Affidavit at 6).

[121] Order No. 745, FERC Stats. & Regs. ¶ 31,322 at P 61.

markets.[122] The Commission has long held that payment of LMP to supply resources clearing in the day-ahead and real-time energy markets encourages more efficient supply and demand decisions in both the short run and long run, notwithstanding the particular costs of production of individual resources.

66. EEI and CSA argue that the possibility that some demand resources that normally purchase energy needs from the RTO or ISO energy market may possess and run behind-the-meter generation in order to continue operation and still collect payments for demand response is a sufficient reason to avoid setting demand response compensation at LMP for all demand response. We do not agree that the existence of behind the meter generation or the potential manner in which behind the meter generation is treated by the RTOs and ISOs invalidates the payment of LMP. As discussed previously, in an RTO or ISO market, payment of LMP is the marginal value of a load reduction in the wholesale market and therefore is reasonable payment for such reduction. From

[122] Order No. 745, FERC Stats. & Regs. ¶ 31,322 at P 62. In this regard, we note that certain generators may receive benefits or savings in the form of credits or in other forms. In these cases, the generators realize a value of LMP plus the credit or savings, but ISOs or RTOs do not take such benefits or savings into account in determining how much to pay those resources. *See* Viridity Comments, at 8 ("examples of those benefits include tax credits for kilowatt-hours produced by generators combusting municipal solid waste and other specified generators under Section 45(a) of the Internal Revenue Code ("IRC"), reductions in fuel costs for generators combusting refined coal due to tax credits under Section 45(e)(8) of the IRC, and the value of renewable energy certificates earned by eligible generators under state renewable portfolio standards"); September 13, 2010 Tr. 67:3-14 (Mr. Peterson).

the perspective of the grid, the manner in which a customer is able to produce such a load reduction from its validly established baseline (whether by shifting production, using internal generation, consuming less electricity, or other means) does not change the effect or value of the reduction to the wholesale grid.[123] Details associated with the use and measurement of behind the meter generation to facilitate demand response are already part of some RTO and ISO tariffs, and any changes to such rules are properly considered either as part of the individual RTO and ISO compliance filings or separate section 205 or 206 filings, as appropriate.

67. We reject the argument that suppression of the LMP will result in unjust and unreasonable prices for generation, causing delay in the construction of new generation while accelerating the retirement of current facilities. First, generation resources will not be subject to unfavorable treatment relative to demand response resources, because both types of resources will receive compensation at the LMP when the conditions of capability and cost-effectiveness are met. Demand response resource participation helps to balance supply and demand, helping to produce just and reasonable energy prices by lowering the amount of higher-cost generation dispatched to satisfy system demand.[124] Second, petitioners' argument ignores the

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[123] The Final Rule required RTOs and ISOs to address measurement and verification issues in their compliance filings. Order No. 745, FERC Stats. & Regs. ¶ 31,322 at P 94. Additionally, the Commission's anti-manipulation regulation continues to prohibit fraudulent demand response schemes in which no genuine load reduction occurs. 18 C.F.R. § 1c (2011); *see, e.g., North America Power Partners*, 133 FERC ¶ 61,089 (2010).

[124] Order No. 745, FERC Stats. & Regs. ¶ 31,322 at P 10.

fact that demand response resources increase competition among supply-side resources in the context of balancing supply and demand. In other words, the Final Rule ensures that RTOs and ISOs treat demand response resources in a manner similar to a generation resource that is introduced into a pool of supply-side resources. Accordingly, the Final Rule treats demand response as an alternative to generation in the context of balancing supply and demand in the energy market.

68. CSA's argument that paying LMP to demand response when cost-effective will result in prices that are too low from the supply standpoint, and even violative of the Fifth Amendment, is unconvincing. As explained above, paying LMP reflects the marginal value of a resource's contribution to the market, regardless of whether that resource provides generation or demand response. By ensuring that both types of resources, when dispatched, receive the same compensation for the same service, we expect the Final Rule to enhance the competitiveness of organized wholesale energy markets and result in just and reasonable rates in accordance with the Commission's mandate under the FPA.[125]

69. CSA, EEI, and Joint Parties argue that the Commission erroneously relies on a presumption that compensation at LMP is the correct payment level.

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[125] The remedy for an alleged taking by the federal government lies in a suit brought in the United States Court of Federal Claims pursuant to the Tucker Act. 28 U.S.C. § 1346(a)(2) (2006); *see Wisconsin Valley Improvement Co. v. FERC*, 236 F.3d 738, 743 (D.C. Cir. 2001) (citing *Transmission Access Policy Study Group v. FERC*, 225 F.3d 667, 690 (D.C. Cir. 2000); *Railway Labor Executives' Ass'n v. United States*, 987 F.2d 806, 815-16 (D.C. Cir. 1993) (citing *Williamson County Regional Planning Comm'n v. Hamilton Bank*, 473 U.S. 172, 195 (1985))).

The Commission, as described in the Final Rule, did not simply presume that LMP is the correct level. As detailed in the Final Rule, the Commission carefully considered the effects of demand response resources on the energy market and found that LMP is warranted when demand response resources can balance supply and demand and are determined to be cost-effective. Under these conditions—that are reasonably tailored to address the capabilities and effects of demand response—demand response resources should be paid the marginal value of energy.

70. While Midwest ISO TOs and Joint Parties dispute whether calculating LMP-G would impose an administrative burden on RTOs and ISOs, the Commission's determination in the Final Rule did not rest primarily on the imposition of such a burden and thus their arguments do not supplant the primary reasoning upon which the Final Rule is based.

b. Effect on Retail Demand Response Programs

71. CSA and EEI argue that the Final Rule may have a detrimental effect on retail-level reforms, such as price-responsive demand programs. As stated in the Final Rule, the pricing reform adopted is directed at demand response participation in organized wholesale energy markets and aims to ensure that rates in those markets are just and reasonable. The Final Rule does not directly affect retail-level demand response programs, nor does it require that demand response resources offer into the wholesale market only. Indeed, the organized wholesale energy markets can and do operate simultaneously with retail-level programs, and each can inform the design of the other. As stated in the Final Rule, the Commission "is not regulating retail rates or usurping or impeding state regulatory

efforts concerning demand response."[126] The effect, if any, experienced by a retail-level program is incidental to the reforms adopted in the Final Rule.

c. Need for a Uniform Requirement

72. Several petitioners argue that the Commission failed to justify why a uniform rule for demand response compensation is needed. This argument is a corollary to the argument that the Commission did not satisfy the requirements of section 206 of the FPA because it failed to make a finding that current demand response compensation is unjust and unreasonable. Therefore, we address them together.

73. The Commission complied with the requirements of section 206. The Commission, on its own motion, initiated the section 206 action that resulted in the Final Rule. In the Final Rule, we found that:

> [W]hen a demand response resource has the capability to balance supply and demand as an alternative to a generation resource, and when dispatching and paying LMP to that demand response resource is shown to be cost-effective as determined by the net benefits test described herein, payment by an RTO or ISO of compensation other than the LMP is unjust and unreasonable.[127]

As explained in the Final Rule and affirmed above, LMP represents the marginal value of an increase in supply or a reduction in consumption at each node within an RTO or ISO, i.e., LMP reflects the marginal value of the last unit of resources necessary to balance supply and demand. LMP has therefore been the

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[126] Order No. 745, FERC Stats. & Regs. ¶ 31,322 at P 114.

[127] *Id*. P 47.

primary mechanism for compensating generation resources clearing in the organized wholesale energy markets since their formation.[128] As a result, we continue to believe that requiring all RTOs and ISOs to pay demand response resources the LMP under the conditions set forth in the Final Rule is appropriate to ensure that those resources are compensated in a manner that reflects the marginal value of those resources to the RTO or ISO.

74. Petitioners state that the Commission, up to this point, evaluated RTO and ISO demand response programs on an individual basis and without reference to a standardized compensation level. We disagree. Order No. 719 was clear that demand response resources participating in competitive ancillary service markets would receive the market clearing price.[129] Petitioners state that the Final Rule is a departure from past Commission practice of encouraging regional variations in RTO and ISO market design. Petitioners cite Order No. 719 as an example of the Commission's support for regional variation, where it directed RTOs and ISOs to work with their stakeholders to address issues involving ancillary services markets. Again, we disagree. In Order No. 719, the Commission recognized the need for RTOs and ISOs to ensure that the technical requirements of allowing demand response resources to offer into the ancillary services markets required each RTO and ISO to examine this question from their own unique perspective, given the differences in markets, but still required comparable pricing between demand

[128] *Id*. P 120.

[129] Order No. 719, FERC Stats. & Regs. ¶ 31,281 P 47.

response and other resources.[130] The Commission acknowledged in the Final Rule that it previously accepted a variety of RTO and ISO proposals for compensation for demand response resources participating in organized wholesale energy markets.[131] Nonetheless, based on the record of the proceeding, and balancing the diverging opinions of noted experts, the Commission determined it was necessary in this instance to adopt a uniform compensation rule for demand response resources participating in the organized wholesale energy markets under the conditions set forth in the Final Rule. We are not convinced by petitioners that this decision was in error. Indeed, our action here is consistent with Order No. 719 that determined RTOs and ISOs must pay the market clearing price to all accepted bids in ancillary services markets.

75. Moreover, the Final Rule allows RTOs and ISOs to exercise discretion with respect to their demand response programs, while balancing the level of prescriptive detail. For example, the Final Rule recognizes that there will be "inherent differences" in the supply curves determined by each RTO or ISO under the net benefits test, and thus varying threshold prices among RTOs and ISOs, attributable to each region's unique supply data, mathematical methods, generation mix, local generation heat rates, and fuel price indices.[132] The Final Rule also recognized that RTOs and ISOs may have different cost allocation and measurement and verification programs. Each

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[130] Order No. 719, FERC Stats. & Regs. ¶ 31,281 *see, e.g.*, P 59.

[131] *Id*. P 47.

[132] *Id*. n.160.

of these elements can be addressed on an individual basis through the RTO and ISO compliance filings.

d. Effect on Market Power

76. CSA argues that the Final Rule seeks to justify the payment of LMP on the ground that current generator market power mitigation rules are inadequate but failed to make a finding that existing market power mitigation rules indeed are inadequate. CSA also cautions that over-mitigation of market power is as harmful as under-mitigation.

77. CSA, however, misinterprets the Commission's reference in the Final Rule to generator market power and the effect of demand response resources on it. The Final Rule states that "[r]emoving barriers to demand response will lead to increased levels of investment in and thereby participation of demand response resources (and help limit potential generator market power), moving prices closer to the levels that would result if all demand could respond to the marginal cost of energy."[133] The Commission emphasized that it sought to facilitate greater competition, with the markets themselves determining the appropriate mix of resources needed by the RTO and ISO to balance supply and demand based on relative bids in the energy markets.[134] The Final Rule does not make a finding that existing generator market power mitigation rules are inadequate, nor was that issue the subject of the rulemaking. The reference to market power was to illustrate the general principle that the greater competition in the market helps to limit potential opportunities for the exercise of market power.

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[133] Order No. 745, FERC Stats. & Regs. ¶ 31,322 at P 59.

[134] *Id.*

78. CSA further argues that the Final Rule facilitates the exercise of buyer market power. The Final Rule addresses arguments concerning a buyers' cartel and cooperative price setting, finding that the requirements of the Final Rule do not convert the unit commitment process into collusion among bidders, whether generation or demand response.[135] CSA has not shown how buyers could in any way collude in setting bids or prices under the Final Rule. Moreover, the market rules implementing the requirements of the Final Rule must be approved by the Commission and demand response resources will be subject to those Commission-approved rules, just like any other participant in the organized wholesale energy markets.

e. Costs of Generation Resources

79. Midwest ISO TOs and Joint Parties argue that the Commission erred when it refused to account for the costs incurred by generator resources to produce electricity. They argue that because generator resources incur costs for fuel, plant operation, etc., when generating electricity, that they are entitled to LMP compensation. In contrast, they claim that because a demand response resource incurs no costs associated with providing its service to an RTO or ISO, that it should receive LMP-G compensation. Again we disagree.

80. As explained in the Final Rule, in the absence of market power concerns the Commission does not inquire into the costs or benefits of production for the individual resources, either generation or demand response resources, participating as supply resources

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[135] *Id*. P 65.

in the organized wholesale energy markets.[136] Just as the Commission found with regard to arguments made in response to the NOPR, we conclude that petitioners have failed to justify why it would be appropriate for the Commission to continue to pay generation resources in a manner that reflects the marginal value of the service provided yet depart from this approach for demand response resources.

C. Net Benefits Test and Determination of the Threshold Price Level

81. In the Final Rule, the Commission found that when a demand response resource participating in an organized wholesale energy market administered by an RTO or ISO has the capability to balance supply and demand as an alternative to a generation resource and when dispatch of that demand response resource is cost-effective as determined by the net benefits test, that demand response resource must be compensated for the service it provides to the energy market at the LMP.

82. The Commission stated that the cost-effectiveness condition, as determined by the net benefits test, recognizes that, depending on the change in LMP relative to the size of the energy market, dispatching demand response resources may result in an increased cost per unit ($/MWh) to the remaining wholesale load associated with the decreased amount of load paying the bill. This is because the use of demand resources produces both effects, a reduction in the use of generation and a reduction in load.[137] We

[136] *Id*. P 62.

[137] If the replacement of generation does not produce a reduction in the LMP (price per unit) then the effective unit price

refer to this potential result as the billing unit effect of dispatching demand response. By contrast, generation resources do not produce this billing unit effect because they do not result in a decrease of billing determinants. To address this billing unit effect, the Commission in the Final Rule requires the use of the net benefits test to ensure that the overall benefit of reduced LMPs that result from dispatching demand response resources exceeds the cost of dispatching and paying LMP to those resources. When the net benefits test is satisfied, and the demand response resource clears in the RTO's or ISO's economic dispatch, the demand response resource is a cost-effective alternative to generation resources for balancing supply and demand.

83. To implement the net benefits test, the Commission directed RTOs and ISOs to make two compliance filings. First, each RTO and ISO is required to develop a mechanism as an approximation to determine a price level at which the dispatch of demand response resources will be cost-effective. The RTO or ISO should determine, based on historical data as a starting point and updated for changes in relevant supply conditions such as changes in fuel prices and generator unit availability, the monthly threshold price corresponding to the point along the supply stack at which the overall benefit from the reduced LMP resulting from dispatching demand response resources exceeds the cost of dispatching and paying LMP to those resources.

84. Second, the Commission indicated that integrating a determination of the cost-effectiveness of

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to each remaining customer would go up because the same resource cost is now spread over fewer megawatt hours.

demand response resources into the dispatch of the RTOs and ISOs may be more precise than the monthly price threshold. The Commission required each ISO and RTO to conduct a study to determine whether the net benefits test could be integrated into its dispatch. Those studies are required to be filed by September 21, 2012.

1. Requests for Rehearing

85. ICC asks whether the determination of the threshold price level should consider demand response resource offers individually, in aggregate, or by some other means.

86. CAISO and P3 argue the Final Rule is arbitrary and capricious and fails to demonstrate reasoned decision making because the net benefits test, which RTOs and ISOs universally opposed, is, according to these petitioners, unworkable. The petitioners state that the Commission ignored significant amounts of record evidence in imposing the net benefits test. Joint Parties also argue that the Commission's net benefits test does not resolve concerns that such a test would be difficult and costly to administer. Midwest TDUs similarly maintain a net benefits test that is too complicated to work. With respect to the integration of demand response into dispatch, Joint Parties quote Andy Ott of PJM Interconnection, L.L.C. (PJM) who, during the technical conference in this proceeding stated that, "an iterative process to look at impacts on market price, my opinion is that would be very costly and difficult to do, if we could even do it."[138] They further state that in requiring compliance filings for the monthly net benefits test, as well as the study of a dynamic process, the Commission did not consider or

[138] September 13, 2010 Tr. 82:16-21 (Mr. Ott).

resolve whether the test is feasible for implementation or whether the cost and burden on RTOs and ISOs of complying with this aspect of the Final Rule is reasonable. They conclude that every indication from the record in this proceeding is that developing a net benefits methodology will be very difficult, if not impossible.

87. CAISO argues that implementing the net benefits test results in similarly-situated resources being treated differently.[139] For example, CAISO states that its tariff provisions governing demand response require that the same methodology be used to evaluate bids from both demand response resources and other supply resources. CAISO argues that the Final Rule requires CAISO to unduly discriminate against demand response resources because such resources must now pass the net benefits test. SWP similarly claims undue discrimination, contending that prior to the Final Rule, no market participant offering in supply was required to make a showing that its offer is cost-effective.[140]

88. CSA and Joint Parties maintain that the monthly net benefits test will not be sufficiently accurate to perform the function for which it was adopted. The petitioners cite to the Commission's acknowledgement that the test may result in Type I and Type II errors,[141] resulting in circumstances where

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[139] CAISO Request for Rehearing at 38.

[140] California Department of Water Resources State Water Project (SWP) Request for Rehearing at 10.

[141] *See* Order No. 745, FERC Stats. & Regs. ¶ 31,322 at P 80.

demand response resources may be dispatched even though doing so is not cost-effective.[142]

89. Midwest ISO TOs maintain the net benefits test adopted by Order No. 745 ignores the fact that demand response will provide different benefits to different customers in different locations, and therefore the Final Rule is arbitrary and capricious because, they argue, it ignores significant arguments raised in NOPR comments and fails to articulate a rational connection between the facts found and the decision made.[143]

90. Midwest TDUs state that the net benefits test will be biased because the "over compensation" required under the rule will result in shifting demand response from state programs to the federal program.[144] As a result, they contend the shift from retail to wholesale demand response programs would drive up the baseline from which the net benefits test measures costs and benefits in the wholesale market. Specifically, they assert that the net benefits test will show consumer cost "savings" associated with the non-consumption behavior that consumers are already enjoying at a lower cost, thus raising total consumer bills.

2. Commission Determination

91. We affirm our determination that a net benefits test is appropriate and workable. As the Commission explained in the Final Rule, dispatching demand response resources may result in an increased cost per

[142] CSA Request for Rehearing at 63; Joint Parties Request for Rehearing at 23-24.

[143] Midwest ISO TOs Request for Rehearing at 26-27.

[144] Midwest TDUs Request for Rehearing at 19-20.

unit to load associated with the decreased amount of load paying the bill (the billing unit effect), depending on the change in LMP relative to the size of the energy market. When reductions in LMP from implementing demand response results in a reduction in the total amount consumers pay for resources that is greater than the money spent acquiring those demand response resources at LMP, such a payment is a cost-effective purchase from the customers' standpoint. In comparison, when wholesale energy market customers pay a reduced price attributable to demand response that does not reduce total costs to customers more than the costs of paying LMP to the demand response dispatched, customers suffer a net loss.[145] Therefore, we find no undue discrimination as alleged by CAISO, since there is a reasonable basis for paying demand response depending on whether it satisfies the net benefits test. When demand response produces a sufficient reduction in LMP to cover the increased billing costs imposed on remaining customers, it is beneficial to customers; when the reduction does not cover costs, the demand response is not beneficial.

92. We also find that it is similarly reasonable to differentiate between demand response and generation as to this issue since only demand response produces the billing unit effect.[146] As the Commission

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[145] *See* Order No. 745, FERC Stats. & Regs. ¶ 31,322 at P 50.

[146] Undue discrimination does not exist when "a rational, non-discriminatory basis existed for the difference." *Consol. Edison Co. v. FERC*, 165 F.3d 992, 1013 (D.C. Cir. 1999); *Bethany v. FERC*, 727 F.2d 1131, 1139 (D.C. Cir. 1984) (the "mere fact of a rate disparity [between customers receiving the same service] does not establish unlawful rate discrimination" under the NGA, and that "rate differences may be justified and rendered lawful by facts—cost of service or otherwise").

stated in the Final Rule, in the absence of the net benefits test, the RTO's or ISO's economic dispatch ordinarily would select demand response when it is the incremental resource with the lowest bid. However, if the avoided cost of the next unit of generation is not sufficient to offset the billing unit effect of the demand response resource, the decrease in LMP multiplied by the remaining load would not be greater than the costs of dispatching the demand response resource. In such a situation, dispatching the demand response resource would result in a higher price to remaining customers than the dispatch of the next unit of generation in the bid stack. While the demand response resource appears cost competitive in the dispatch order, selection of the demand response resource increases the total cost per unit to remaining load, and it would not be cost-effective to dispatch the demand response resource.[147]

93. We reject the arguments that the net benefits test we are requiring is unworkable. In the Final Rule, we provided an explanation of how to conduct that test. Indeed, five of the six RTOs and ISOs (including CAISO) have submitted compliance filings related to the calculation of the price threshold and the implementation of the net benefits tests, with what they assert are workable versions of the net benefits test, contrary to CAISO, P3, Joint Parties and Midwest TDUs' assertions.[148] The Commission will address

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[147] *See* Order No. 745, FERC Stats. & Regs. ¶ 31,322 at P 52.

[148] We note that Southwest Power Pool, Inc. (SPP) did not submit a net benefits test in its Order No. 745 compliance filing because it argues that its existing demand response program is consistent with or superior to the demand response programs required by Order No. 745, and does not require a net benefits test to determine the hours when to pay full LMP to demand

implementation of the net benefits tests when it acts on those filings.

94. CSA and Joint Parties maintain that the Commission cannot justify implementing the net benefits test when the Commission itself recognized that it is not perfectly accurate. We recognize that the test we are requiring may result in instances both when demand response is not paid the LMP but would have been cost-effective and when demand response is paid the LMP but is not cost-effective; however, we find that the test we are requiring is reasonably calculated to identify the hours in which it is reasonable to pay demand response LMP for participation in the day-ahead and real-time energy markets.[149] As we acknowledged in the Final Rule, a more accurate method would be to include demand response, including the concomitant reduction in demand, as part of the RTO or ISO dispatch algorithm. However, it was not clear that RTOs and ISOs could implement the required changes to the dispatch algorithm, so as a practical accommodation we adopted a reasonable,

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response resources because it pays full LMP in all hours. We will address the merits of that argument in the order on compliance. Likewise, we also addressed CAISO's, Midwest Independent Transmission System Operator, Inc's (MISO), and PJM's net benefits tests in their respective orders on compliance. *See CAISO*, 137 FERC ¶ 61,217 (2011); *MISO*, 137 FERC ¶ 61,212 (2011); *PJM*, 137 FERC ¶ 61,216 (2011).

[149] *See Batavia v. FERC*, 672 F.2d 64, 84 (D.C. Cir. 1982) (the billing design need only be reasonable, not theoretically perfect); *North Carolina v. FERC*, 112 F.3d 1175, 1190 (D.C. Cir. 1997) ("An agency need not have perfect information . . . [it] need only explain the evidence which is available, and . . . offer a rational connection between the facts found and the choice made." (internal quotation and citation omitted)).

and more easily administered mechanism for the net benefits test.

95. We deny Midwest ISO TOs' request for rehearing arguing that the net benefits test does not acknowledge the fact that demand response provides different benefits to different customers in different locations, and therefore the Final Rule is arbitrary and capricious. Midwest ISO TOs' argument is raised here in the abstract, however, we have specific compliance filings before us that propose methods of determining the price threshold based on historical data in the RTOs. Midwest ISO TOs' argument is more appropriate for the Midwest ISO Order No. 745 compliance filing, where we can determine whether the net benefits test filed by the Midwest ISO appropriately measures the benefits of demand response.

96. Midwest TDUs argue that demand response resources shifting from retail to wholesale demand response programs caused by "over compensation" would drive up the baseline from which the net benefits test measures costs and benefits in the wholesale market leading to phantom benefits. As discussed previously, we do not find that paying LMP is over compensation; rather, it fairly compensates demand resources at the marginal value of their contribution. The net benefits test determines whether paying demand response at the LMP is cost-effective. The Final Rule does not attempt to measure what would have happened in a retail program absent the wholesale program. Rather, it is focused on the net price effect of paying the demand response resources the LMP in the wholesale market.

97. We believe ICC is asking whether the RTO or ISO is supposed to consider small changes (1 MW) changes or the full amount of demand response when

it looks for the point where the price elasticity of supply is one. This issue is more appropriately raised in the individual compliance filings in which the RTOs sought to comply with the requirement. Additionally, we note that the Commission's directive to smooth the representative supply curve,[150] thus employing a calculus-based operation into the threshold determination which looks at very small movements along the supply curve when calculating the elasticity, addresses ICC's concern.

D. Cost Allocation

98. The Final Rule explained that when a demand response provider curtails, the RTO or ISO experiences a reduction in load with a corresponding reduction in billing units through which the RTO or ISO derives revenue (billing unit effect). When the two conditions described in the Final Rule are met, however, the RTO must pay LMP to both generators and demand response providers for the resources that clear the energy market. The difference between the amount owed by the RTO or ISO to resources, including demand response providers, and the revenue it derives from load results in a negative balance that must be addressed through cost allocation. Therefore, the Final Rule concluded that a method is needed to ensure that RTOs and ISOs recover the costs of obtaining demand response.[151]

99. The Final Rule requires each RTO and ISO to include in their compliance filing a proposed method of allocating the costs associated with demand response compensation proportionally to all entities

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[150] Order No. 745, FERC Stats. & Regs. ¶ 31,322 at n.161.

[151] *Id*. P 99.

that purchase from the relevant energy market in the area(s) where the demand response reduces the market price for energy at the time when the demand response resource is committed or dispatched.[152]

1. Requests for Rehearing

100. DR Supporters seeks clarification that the costs associated with demand response compensation include the costs of paying all resources LMP *and* the wholesale costs associated with deviations to the load of load serving entities (LSEs) who host demand response.[153] DR Supporters argues that the reduction in load attributable to demand response shows up as a deviation in the load of the LSE who hosts the demand response. DR Supporters therefore requests that the Commission explicitly define the need to settle at wholesale for deviations to LSE load caused by demand response as a cost associated with demand response compensation.[154]

101. DR Supporters contends that LSEs scheduling load in the day-ahead market take on a binding

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[152] *Id*. P 102.

> Since the dispatch of demand response resources affects the LMP charged, and will result in a lower LMP, the customers benefitting from that lower LMP depends upon transmission constraints, and the price separation such constraints cause within the RTO [or ISO]. In some hours in which transmission constraints do not exist, RTOs [and ISOs] establish a single LMP for their entire system (a single pricing area) in which case the demand response would result in a benefit to all customers on the system. When transmission constraints are present, however, LMPs often vary by zone, or other geographic [area].

Id. P 100.

[153] DR Supporters Request for Rehearing at 4-6, 10-11.

[154] *Id*. at 2.

settlement obligation for a specified amount of load, which is matched by an obligation to settle in real-time for deviations from load scheduled day-ahead.[155] DR Supporters argues that when negative real-time deviations arise from the operation of demand response that was scheduled as a day-ahead resource, a settlement imbalance results. According to DR Supporters, the ISO must collect enough money to not only pay all resources LMP, but also to settle for any negative real-time deviations caused by demand response scheduled day-ahead. DR Supporters argues that this collection is necessary to hold the LSE harmless and prevent the imposition of a penalty to LSEs whose customers engage in demand response.[156]

102. CSA requests clarification, or rehearing, that the Final Rule requires that costs associated with demand response compensation should be allocated to net purchasers (i.e., market participants whose net cleared demand exceeds their net cleared supply).[157] CSA asserts that it is indisputable that market participants that self-supply their energy needs do not benefit from lower LMPs resulting from dispatching demand response, and, as such, should not be allocated any demand response costs.[158] CSA states that to allocate costs to an entity that does not benefit from demand response would be inconsistent with the reasoning in the Final Rule that costs associated with demand response compensation should be allocated among those who benefit from the resultant lower LMP. Furthermore, CSA argues that such cost

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[155] *Id*. at 4-5.

[156] *Id.* at 5.

[157] CSA Request for Rehearing at 64.

[158] *Id*. at 65.

allocation would also undermine the operation of the net benefits test by understating the billing unit effect by allocating costs to self-supply, which does not benefit from price decreases.[159]

103. A number of parties request rehearing based on assertions that the cost allocation method approved in the Final Rule does not adequately account for operational realities,[160] is vague,[161] or is too complicated to implement.[162]

104. Joint Parties request rehearing arguing that the Commission failed to clarify the cost allocation methodology. Joint Parties argue that the Final Rule does not define "all entities" as well as the "area(s)" subject to paying for the demand response compensation. Nor does the Final Rule, according to Joint Parties, explicitly state whether the areas for cost allocation must follow the designation of LMPs and thus is not sufficiently clear. Joint Parties request that the Commission clarify that it will address these issues on a case-by-case basis in the compliance filing.[163]

105. OMS requests rehearing arguing that the Commission's determination to allocate the costs of load reductions across an indefinite region is not just and reasonable because the approved cost allocation provides no incentive for LSEs to improve their rate structures and, furthermore, the Final Rule is not clear with respect to how the regions to which costs

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[159] *Id*. at 66.

[160] OMS Request for Rehearing at 7-8.

[161] Joint Parties Request for Rehearing at 26-27.

[162] EEI Request for Rehearing at 25.

[163] Joint Parties Request for Rehearing at 27.

will be allocated will be determined.[164] OMS argues the Final Rule does not describe how "relevant market area(s)" will be determined. OMS contends that by their very nature RTO energy markets are dynamic and the algorithms used to compute LMPs are complex. OMS believes it may be impossible to conduct an after-the-fact analysis to determine the effect of a load reduction on hundreds or thousands of pricing nodes in order to make a determination as to where and when nodal LMPs were affected by a load reduction.[165]

106. EEI contends that the cost allocation methodology fails to account for the complexities that can arise from transmission congestion by overlooking the reality that demand response can relieve congestion, thereby changing the boundaries of one or more transmission congested areas.[166] EEI argues that the benefits to each wholesale buyer as a result of the demand response participation must be calculated through computer simulation of the counterfactual case of no demand response and compared with the actual case. EEI contends that allocating recovery of the demand response payments in proportion to wholesale buyers' benefits will then be complex and cannot be accomplished through the methodology in the Final Rule.[167] EEI reasserts its support for the bifurcated methodology[168] for cost allocation that the

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[164] OMS Request for Rehearing at 8.

[165] *Id.* at 7-8.

[166] EEI Request for Rehearing at 24-25.

[167] *Id*. at 25.

[168] Under a bifurcated methodology, a portion of the total cost is allocated to the load serving entity (LSE) that serves the demand response resource, while the balance is allocated to the remaining LSE(s) that serve the zone that harbors the demand

Commission argued in the Final Rule represented an arbitrary division of cost responsibility without regard to the degree to which each received benefits.

107. Midwest TDUs request rehearing arguing that the Final Rule's cost allocation requirement is very difficult and time-consuming because it will require RTOs and ISOs to estimate, on an ongoing basis, hypothetical LMPs that would have existed but for the participation of demand response resources in the organized wholesale energy market.[169]

108. ICC requests clarification that costs should be allocated according to the degree to which each load benefits from price reductions and not simply based on each benefiting load's portion of total load. ICC argues that when a transmission constraint exists, a demand response resource may reduce the price in one pricing node, but not at another. Furthermore, ICC contends that the magnitude of the price decrease at two pricing nodes that experience a price decrease may be significantly different.[170] Therefore, ICC argues that, in order to determine those entities that benefit from lower LMPs, the RTO or ISO must be able to identify which LMPs will be reduced when demand response participates.[171] ICC states that in order to determine the pricing nodes at which LMPs are decreased, RTOs and ISOs need to simulate a scenario where demand response did not participate in order to determine the prices at each node under the assumption that demand response was not allowed to participate. The

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response resource. *See*, *e.g*., PJM May 13, 2010 Comments at 12; ISO-NE May 13, 2010 Comments at 5

[169] Midwest TDUs Request for Rehearing at 14.

[170] ICC Request for Rehearing at 14.

[171] *Id*. at 15.

RTO or ISO could compare those prices to the actual prices to determine which pricing nodes actually benefited as a ratio of total benefits.

109. Midwest ISO TOs request rehearing arguing that Order No. 745 contravenes the Commission's cost causation policy that costs should be allocated to entities that cause or benefit from the incurrence of the costs.[172] Midwest ISO TOs argue that the net benefits test established in the Final Rule ignores the fact that significant benefits of demand response are realized at the local or nodal level.[173] Midwest ISO TOs argue that a market-wide net benefits test allocates costs equally to all market participants, notwithstanding the fact that market participants located in the same area as the demand response resource will realize a greater benefit from the reduction in LMP resulting from the demand response resource's participation in the energy market.[174] Midwest ISO TOs assert that to the extent that the Final Rule ignores the locational impact that demand response has on different components of LMP and mandates allocation of costs based on a market-wide net benefits test, the Final Rule represents a lack of reasoned decision-making. Midwest ISO TOs request clarification that RTOs and ISOs can develop cost allocation mechanisms that consider the respective regional and localized benefits provided by deployment of demand response resources.[175]

110. EEI requests rehearing arguing that the cost allocation methodology required in the Final Rule

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[172] Midwest ISO TOs Request for Rehearing at 27.

[173] *Id.*

[174] *Id*. at 28.

[175] *Id*.

produces cross-subsidies among wholesale buyers and thus violates the cost causation principle of assigning costs in proportion to benefits received.[176] EEI further argues that the cost allocation methodology thwarts the ability of retail regulatory authorities to offset at the retail level what is, according to EEI, inefficient wholesale pricing because the cross-subsidies are broadly spread over LSE and retail jurisdictional boundaries.[177] Furthermore, EEI states that the cross-subsidies created by the cost allocation methodology effectively disconnect LSE payments for purchased energy from the payments their respective retail customers enjoy by providing demand response.[178] Thus, even if retail regulators could recapture the payments to these retail customers through retail rates, EEI believes doing so will not make their LSEs indifferent because of the cross-subsidies created by the Final Rule.[179]

2. Commission Determination

111. The Commission denies the requests for rehearing and affirms its finding that each RTO and ISO allocate the costs associated with demand response compensation proportionally to all entities that purchase from the relevant energy market in the area(s) where the demand response resource reduces the market price for energy at the time when the demand response resource is committed or dispatched. As the Commission explained in the Final Rule, when a demand response provider curtails, the RTO experiences a reduction in load with a corresponding

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[176] EEI Request for Rehearing at 22.

[177] *Id*. at 23.

[178] *Id*. at 28.

[179] *Id*. at 29.

reduction in billing units through which the RTO derives revenue.[180] When the demand response resource has the capability to provide the service and when payment of the service is cost effective, however, the RTO must pay LMP to both generators and demand response providers for the resources that clear the energy market. The difference between the amount owed by the RTO to resources, including demand response providers, and the revenue it derives from load results in a negative balance that must be addressed through cost allocation. The Commission continues to find its cost allocation method just and reasonable as it will reasonably allocate the costs of demand response to those who benefit from the lower prices produced by dispatching demand response.

112. We deny DR Supporters' request for clarification as to whether the demand response costs to be allocated by the Final Rule should include costs associated with deviations from day-ahead market commitments made by an LSE that supplies energy to demand response providers, which it incurred as a result of serving those demand response providers. However, DR Supporters' argument assumes that an LSE is obligated to procure its full load (without taking into account the reduction in load from demand response) thus leaving it with a potential deficiency that would carry over to the real-time market.[181]

113. DR Supporters recognize that different RTOs and ISOs treat real-time settlement imbalances differently at present, where these imbalances may be positive or negative. Because of the differences in the way RTO's or ISO's operate their energy markets, we

[180] Order No. 745, FERC Stats. & Regs. ¶ 31,322 at P 99.

[181] DR Supporters Request for Rehearing at 7-8.

cannot resolve this issue on a generic basis. To the extent DR Supporters or other parties raise this issue in the compliance filings, we will address the issue on a case-by-case basis in the individual compliance proceedings.

114. Petitioners also challenge the allocation of costs associated with compensation for demand response resources to market participants that primarily self-supply. The cost allocation methodology required in the Final Rule is based upon the benefits of demand response to wholesale load. As explained in the Final Rule, and under the principle of cost causation, purchasers are allocated the costs of demand response because they receive a benefit through the lower LMP that results from demand response resource participation in the organized wholesale energy markets.[182] We reiterate here that cost allocation proposals must satisfy the cost causation principle. However, we find that the record in this proceeding is insufficient to resolve on a generic basis the issue of cost allocation to participants that self-supply. We further find that the issue is better addressed in the individual RTO and ISO compliance proceedings, to the extent concerns have been raised there. We therefore deny the requests for rehearing on this issue.

115. The Commission also denies OMS' and Joint Parties' requests for rehearing regarding clarification and definition of the terms "all entities" and the "area(s)" subject to paying for the demand response compensation. The cost allocation methodology required by the Final Rule was designed to allow sufficient flexibility for each individual RTO and ISO to determine, in consultation with their stakeholders,

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[182] Order No. 745, FERC Stats. & Regs. ¶ 31,322 at P 100.

an appropriate cost allocation methodology that complies with the Final Rule.[183] In this way, the Commission is allowing for regional variation in the determination of the "area(s)" in which market participants benefit from demand response participation based on the unique energy market design in each RTO and ISO. The Commission will analyze and evaluate each RTO's and ISO's proposed cost allocation methodology on a case-by-case basis in its compliance filing.

116. We further deny EEI's, OMS', and Midwest TDUs' requests for rehearing asserting that the cost allocation methodology prescribed in the Final Rule will be overly complex to implement. OMS argues that RTOs and ISOs will have to conduct after-the-fact analysis to determine the effect of demand response on hundreds or thousands of pricing nodes. EEI and Midwest TDUs claim that RTOs and ISOs will have to calculate hypothetical counterfactual LMPs that would have occurred with no demand response participation in order to determine the benefits of demand response participation.

117. The Final Rule requires no such specific actions on the part of RTOs and ISOs. The Final Rule allows each RTO and ISO to tailor its cost allocation methodology to the circumstances on its system.[184] Any issues with respect to the allocation of costs resulting from these proposals, or the feasibility of conducting the analysis, can be raised on a case-by-case basis in the compliance filing proceedings.

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[183] Order No. 745, FERC Stats. & Regs. ¶ 31,322 at P 102.

[184] *Id.*

118. We deny ICC's, Midwest ISO TOs', and EEI's rehearing requests relating to the proper allocation of costs as more appropriately addressed in the individual compliance filing proceedings.

119. The Final Rule does not require, as ICC suggests, that RTOs and ISOs simulate a scenario to calculate what the prices at each node would have been if demand response had not participated in order to determine which pricing nodes actually benefited as a ratio of total benefits. Each RTO or ISO can propose a methodology that reasonably allocates the costs of demand response, consistent with the requirements of the Final Rule.[185]

120. Finally, we reject Midwest ISO TOs' and EEI's requests for rehearing arguing that the cost allocation methodology prescribed by the Final Rule violates the cost causation policy which requires that costs should be allocated to those entities that benefit from the incurrence of the costs. Contrary to Midwest ISO TOs' and EEI's assertions, the cost allocation methodology prescribed in the Final Rule does not prevent an RTO or ISO from accounting for the regional or local benefits provided by deploying demand response resources. As the Final Rule explained, in some hours in which transmission constraints do not exist, RTOs establish a single LMP for their entire system (a single pricing area) in which case the demand response would result in a benefit to all customers on the system. When transmission constraints are present, however, LMPs often vary by zone, or other geographic areas.[186] The RTOs and ISOs need to look at their systems and determine what methodology

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[185] *Id.*

[186] *Id*. P 100.

best allocates cost to the customers benefitting from the lower LMP resulting from demand response.

E. Measurement and Verification

121. In the Final Rule, the Commission agreed with commenters that measurement and verification are critical to the integrity and success of demand response programs but found that, because it was not requiring payment of LMP in all hours, but, rather, subject to a net benefits test, the Final Rule did not directly implicate measurement and verification issues. Nevertheless, the Commission noted the importance of baseline calculation methodologies and the measuring and verifying of demand response resource performance. Therefore, the Final Rule directed each RTO and ISO to review their current requirements in light of the changes required therein and develop appropriate revisions and modifications, if necessary, to ensure that their baselines remain accurate and that they can verify that demand response resources have performed. Each RTO and ISO was required to include as part of its compliance filing an explanation of how its measurement and verification protocols will continue to ensure that appropriate baselines are set, and that demand response will continue to be adequately measured and verified. Additionally, the Commission stated that each RTO and ISO should propose any changes necessary to ensure that their measurement and verification will adequately capture the performance or non-performance of each participating demand response resource, consistent with the Final Rule.

1. Requests for Rehearing

122. CSA and Midwest TDUs request rehearing arguing that the Commission's determination to adopt

the Final Rule in the absence of measurement and verification standards capable of preventing gaming and manipulation is arbitrary and capricious. The petitioners argue that the Final Rule creates significant, and perhaps insurmountable, difficulties and costs for RTOs and ISOs in measuring customers' demand reductions and verifying that they have reduced consumption in response to price signals. The petitioners assert that current measurement and verification standards are not capable of performing the functions they are intended to serve, in particular preventing manipulation. The petitioners further assert that evidence in the record unequivocally indicates that current North American Energy Standards Board (NAESB) standards and RTO and ISO rules cannot prevent fraud and abuse. The petitioners conclude that the Commission's determination that RTOs and ISOs will be able to solve the problems created by the Final Rule regarding measurement and verification is arbitrary and capricious decision making.

2. Commission Determination

123. We deny the requests for rehearing on this issue. Petitioners reiterate the same general concerns regarding deficits in the RTO and ISO demand response measurement and verification programs as they did in their comments to the NOPR. In response, the Commission in the Final Rule required RTOs and ISOs to evaluate their measurement and verification protocols taking into account the effect of the Final Rule's directives and develop modifications as necessary, and include any such modifications in the required compliance filing. The Commission did not find that the compensation-related requirements of

the Final Rule fundamentally changed the measurement and verification standards that the RTOs and ISOs have been using. Petitioners will have additional opportunities to address specific concerns about particular aspects of individual RTO or ISO measurement and verification programs in the compliance filing proceedings.[187]

F. Study Regarding the Dynamic Implementation of the Net Benefits Test into the Dispatch Algorithm

124. In the Final Rule, the Commission stated that it believed that integrating a determination of the cost-effectiveness of demand response resources into the dispatch of RTOs and ISOs may be more precise than the monthly price threshold and, therefore, provide the greatest opportunity for load to benefit from participation of demand response in the organized wholesale energy market administered by an RTO or ISO. The Commission acknowledged the position of several of the RTOs and ISOs that modification of their dispatch algorithms to incorporate the costs related to demand response may be difficult in the near term. In light of those concerns, the Commission required each RTO and ISO to undertake a study examining the requirements for and impacts of implementing a dynamic approach which incorporates the billing unit effect in the dispatch algorithm to determine when paying demand response resources the LMP results in net benefits to customers in both the day-ahead and real-time energy

[187] In addition, we note that petitioners may participate in the proceedings considering NAESB Phase II measurement and verification standards development. *See* NAESB, Measurement and Verification of Demand Response Products Phase II Report, Docket No. RM05-5-020 (filed May 3, 2011).

markets. The Commission directed each RTO and ISO to file the results of this study with the Commission on or before September 21, 2012.

1. Requests for Rehearing

125. ICC argues that, unlike in the case of the static model, in the dynamic model, demand-side bidders will not know whether their bids will be cost-effective when they place their bids. ICC states that bidders will have to include a risk premium to account for this uncertainty, which will lead to inefficient prices and levels of demand response resource participation in the RTO and ISO markets. Therefore, ICC asks the Commission to clarify that the dynamic cost-effectiveness model produces uncertainty regarding the offer level at which a demand response resource decides to submit its demand response. ICC also asks the Commission to clarify that this aspect of the dynamic model could have adverse impacts for the development of demand response in the RTO and ISO markets.

126. Joint Parties argue that the Commission's net benefits test does not resolve concerns that such a test would be difficult and costly to administer. Joint Parties cite to a statement by Andy Ott of PJM during the technical conference in this proceeding, "an iterative process to look at impacts on market price, my opinion is that would be very costly and difficult to do, if we could even do it." They further state that in requiring compliance filings for the study of a dynamic process, the Commission does not consider or resolve whether the test is feasible for implementation or whether the cost and burden on RTOs and ISOs of complying with this aspect of the Final Rule is reasonable. They conclude that every indication from the record in this proceeding is that

development of a net benefits methodology will be very difficult, if not impossible, to do.

2. Commission Determination

127. ICC contends that the dynamic cost-effectiveness model will produce uncertainty regarding the level at which demand response resources will offer into the market, but the requirement in the Final Rule is simply that RTOs and ISOs make a compliance filing that includes the results of a study examining the requirements of, costs of, and impacts of implementing a dynamic cost-effectiveness model. The Commission does not expect that a demand response provider will know the magnitude of the billing unit effect associated with its demand reduction *ex ante*, but if it bids its marginal opportunity cost (as we would expect in a competitive market), it will only be called when it is in the demand response provider's economic interest to reduce consumption. All resources, both supply side and demand side, face some degree of uncertainty as to whether they will be dispatched but if a resource bids its marginal opportunity cost it will not be dispatched unless it is in its economic interest. Furthermore, the Commission will not speculate, as ICC would have us do, as to the specific results that a dynamic cost-effectiveness model may produce. The Final Rule required the study to permit a further comprehensive evaluation of the impacts associated with implementing a dynamic approach, therefore we find it appropriate to refrain from making findings in response to ICC's assertions at this time.

128. We reject Joint Parties argument that in requiring compliance filings for the study of a dynamic process, the Commission did not consider or resolve whether the test is feasible for implementation or whether the cost and burden on RTOs and ISOs of

complying with this aspect of the Final Rule is reasonable. Further exploration of these issues is precisely the reason the Final Rule required a study rather than imposing this condition at this time.[188] We are asking the RTOs and ISOs to study the feasibility and giving them sufficient time to do so; the RTOs and ISOs will assess the difficulty of implementing such a plan and report back to the Commission. The Commission can assess the feasibility of implementing a dynamic process in RTOs and ISOs after it receives the studies.

G. Applicability of Order No. 745 to Circumstances When it is not Cost-Effective to Dispatch Demand Response Resources

129. In the Final Rule, the Commission stated that it was not requiring the compensation of full LMP when demand response resources do not satisfy the capability and cost-effectiveness conditions noted above.[189] The Commission's findings in the Final Rule do not preclude the Commission from determining that other approaches to compensation would be acceptable when these conditions are not met.[190]

1. Requests for Rehearing

130. ICC requests that the Commission clarify how the price threshold will work for a demand response resource that bids below the threshold. Specifically, ICC asks whether such a resource would be dispatched if the LMP were below the price threshold, but above

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[188] *See* Order No. 745, FERC Stats. & Regs. ¶ 31,322 at P 84.

[189] Order No. 745, FERC Stats. & Regs. ¶ 31,322 at P 3.

[190] *Id.* P 3 n.6.

the resource's bid. If so, ICC asks how such a demand resource should be compensated.

2. Commission Determination

131. As noted above, in Order No. 745 the Commission, acting pursuant to section 206 of the FPA, required each RTO and ISO to revise its tariff to pay a demand response resource the market price for energy (i.e., the LMP) when two conditions are met. First, the demand response resource must have the capability to balance supply and demand as an alternative to a generation resource. Second, dispatch of the demand response resource must be cost-effective as determined by a net benefits test.[191] We clarify that pursuant to this section 206 directive, each RTO and ISO must revise its tariff to provide that when the LMP is greater than or equal to the threshold price, all demand resources that qualify for compensation[192] will receive the LMP payment. The Commission's section 206 action in Order No. 745 did not extend, however, to situations where the LMP is not greater than or equal to the threshold price. Thus, if LMP is less than the threshold price, the Final Rule does not apply to determine the payment to a demand response resource, and any payment will be governed by the existing RTO or ISO tariff.

H. Effect of Order No. 745 on CAISO's Demand Response Programs

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[191] *See supra* P 54.

[192] For example, a qualification may include a requirement that the demand response resource submit a successful supply offer, whether that successful bid is below, at or above the threshold price.

132. In the Final Rule, the Commission explained that the cost-effectiveness condition for dispatching and compensating demand response resources at the LMP, as determined by the net benefits test, recognizes that, depending on the change in LMP relative to the size of the energy market, dispatching demand response resources may result in an increased cost per unit ($/MWh) to the remaining wholesale load associated with the decreased amount of load paying the bill.[193]

133. The Commission further required each RTO and ISO to allocate the costs associated with demand response compensation proportionally to all entities that purchase from the relevant energy market in the area(s) where the demand response reduces the market price for energy at the time when the demand response resource is committed or dispatched.[194]

1. Requests for Rehearing

134. Rehearing requests were received on three basic issues: the California Proxy Demand Resource Product, Reliability Demand Response Resource Products, and its Participating Load Program.

a. Proxy Demand Resource Product

135. CAISO and CPUC request clarification and rehearing that the Final Rule does not require any change to[195] nor does it expressly or implicitly modify or overturn[196] the default load adjustment feature

[193] Order No. 745, FERC Stats. & Regs. ¶ 31,322 at P 3.

[194] *Id*. P 102.

[195] CAISO Request for Rehearing at 21.

[196] Public Utilities Commission of the State of California (CPUC) Request for Rehearing at 5.

of CAISO's FERC-approved demand response tariff provisions.[197] CAISO states that although the Final Rule contains no directives that squarely address the default load adjustment, or the wholesale double payment issue, it believes that the Final Rule could be read to indirectly require the elimination of it.[198] CAISO contends that the operation of the net benefits test, required in the Final Rule, appears to be inconsistent with the default load adjustment.[199] The net benefits test, described in the Final Rule, considers whether demand response resources should receive full LMP, based on a consideration of overall decreased energy cost spread over the decreased metered load, but the default load adjustment function of CAISO's existing market rules prevents a decrease in an LSE's metered load due to a cleared Proxy Demand Resource bid.

136. CAISO similarly requests clarification arguing that the provisions of the Final Rule relating to cost allocation could also be read as indirectly requiring elimination of the default load adjustment.[200] CAISO argues that the cost allocation methodology for payments made to Proxy Demand Resources under the existing CAISO tariff satisfies and complies with the Commission's directive in the Final Rule because LMP payments made to Proxy Demand Resources are allocated to the load that benefits, i.e., to all load day-ahead and to deviations in real-time.[201]

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[197] *Cal. Indep. Sys. Operator Corp.*, 132 FERC ¶ 61,045 (2010).

[198] CAISO Request for Rehearing at 21-22.

[199] *Id.* at 21.

[200] *Id.* at 23.

[201] *Id.* at 23-24.

137. CAISO and the CPUC request rehearing arguing that the Final Rule does not include any factual or legal analysis as to why CAISO's FERC-approved Proxy Demand Resource is no longer just and reasonable and thus FERC's decision was arbitrary, capricious, and not the product of reasoned decision-making because FERC has failed to explain its inconsistency with its own precedent.[202]

b. Reliability Demand Response Products

138. CAISO and CPUC seek clarification as to whether Reliability Demand Response Resources are subject to the requirements of the Final Rule.[203] CAISO states that this product occupies a gray area under the definition of programs subject to the Final Rule.[204] According to CAISO, Reliability Demand Response Resources will be participating in the day-ahead and real-time energy markets administered by CAISO pursuant to bids submitted for their energy.[205] CAISO states that the product is built on the same platform as, and will have many similarities to, the Proxy Demand Resource Product.[206] However, CAISO states that its proposed tariff provisions for Reliability Demand Response Resources will provide compensation for demand response providing reliability and emergency relief in real-time.[207]

c. Participating Load Program

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[202] CPUC Request for Rehearing at 10-11; CAISO Request for Rehearing at 26.

[203] CAISO Request for Rehearing at 32.

[204] *Id*. at 33.

[205] *Id.*

[206] *Id.* at 15.

[207] *Id*. at 33.

139. SWP seeks clarification or rehearing arguing that to the extent Order No. 745 imposes a net benefits test on demand response from Participating Loads, the order fails to address SWP's evidence and argument which it contends shows that a net benefits test is not necessary for wholesale Participating Loads, which unlike retail demand response, do not use an administrative baseline against which curtailments are measured.[208] SWP states that it requested an exemption from any net benefits test for wholesale demand response that, unlike retail demand response, is modeled as negative generation by CAISO, buys its baselines and is scheduled and settled at nodal LMP levels comparable to generation while retail load uses an averaged or zonal LMP.[209]

2. Commission Determination

140. We find that we cannot assess these individual aspects of CAISO's demand response program on rehearing in a Final Rule. Other parties need the opportunity to respond to these issues, which are best resolved in CAISO's compliance and Reliability Demand Response Resource proceedings.[210] These issues were raised by various parties in CAISO's compliance and Reliability Demand Response Resource proceedings, and the Commission will respond appropriately in those proceedings. Under the exercise of the Commission's authority under section 206 of the FPA, the Commission determined that any

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[208] SWP Request for Rehearing at 4.

[209] SWP Request for Rehearing at 5; *see also* SWP October 13, 2010 Comments at 2-3.

[210] CAISO's Reliability Demand Response Resource proposal is pending before the Commission in Docket Nos. ER11-3616-000 and 001.

energy market demand response program is unjust and unreasonable if it does not pay LMP to demand resources when a net benefits test is satisfied and does not allocate costs appropriately to those parties that benefit from the reduction in LMP occasioned by the demand response. As discussed above, we had an adequate basis for making these determinations on a generic basis.

141. Whether the current contours of CAISO's demand response program meets these criteria can be determined only upon review of CAISO's compliance filing and the full record developed in that proceeding. For example, the Final Rule required that RTOs and ISOs allocate the costs of demand response to those parties that benefit from the reduction in LMP. We cannot determine on this record whether the existing cost allocation in the CAISO market meets these criteria. We similarly cannot determine whether CAISO's Reliability Demand Response Resource program or its wholesale Participating Load Program is covered by the Final Rule without the full record developed in the compliance filing and Reliability Demand Response Resource proceedings.

I. Compliance with the Regulatory Flexibility Act

142. The Regulatory Flexibility Act of 1980[211] (RFA) generally requires an administrative agency to perform an analysis of rulemakings that will have a significant economic impact on a substantial number of small entities. The RFA mandates consideration of regulatory alternatives that accomplish the stated objectives of a proposed rulemaking while minimizing any significant economic impact on a substantial number of small entities. The Small Business

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[211] 5 U.S.C. §§ 601-612.

Administration's (SBA) Office of Size Standards develops the numerical definition of a small business.[212] The SBA has established a size standard for electrical utilities, stating that a firm is small if, including its affiliates, it is primarily engaged in the transmission, generation, and/or distribution of electric energy for sale and its total electric output for the preceding twelve months did not exceed four million MWh.[213]

143. In the Final Rule, the Commission noted that the regulations promulgated in the Final Rule directly impact only RTOs and ISOs. Because RTOs and ISOs are not small entities as defined by the SBA, the Commission certified that the Final Rule would not have a significant economic impact on a substantial number of small entities.

144. Competitive Power Supplier Associations, PPL Parties, and P3 all assert that the Final Rule will, contrary to the Commission's assessment, have an impact on small entities as defined by the SBA. The petitioners assert that the Final Rule will affect small generators, marketers, LSEs, and demand response providers. The petitioners state that the Commission failed to recognize, simply ignored, or did not support its conclusion regarding the impacts that the Final Rule would have on small entities.[214]

145. The only entities subject to the requirements of the Final Rule are the RTOs and ISOs, which as demonstrated in the Final Rule are not classified as

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[212] 13 C.F.R. § 121.101 (2011).

[213] 13 C.F.R. § 121.201, Sector 22 Utilities & n.1.

[214] Competitive Power Supplier Associations Request for Rehearing at 81; PPL Parties Request for Rehearing at 22; P3 Request for Rehearing at 16.

small entities.[215] Furthermore, courts have held that the RFA does not require an agency to perform a regulatory flexibility analysis of impacts on small entities when a rule only indirectly impacts them.[216] In the context of the organized wholesale energy markets, any effects on other entities, such as generators or marketers, are indirect and are the result of competition in the energy market.

The Commission orders:

(A) The requests for rehearing are hereby denied, as discussed in the body of this order.

(B) The requests for clarification are hereby granted in part, and denied in part, as discussed in the body of this order.

By the Commission. Commissioner Moeller is dissenting with a separate statement attached.

(SEAL)

Nathaniel J. Davis, Sr.
Deputy Secretary

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[215] Order No. 745, FERC Stats. & Regs. ¶ 31,322 at P 122-28.

[216] Indirect effects do not fall within the ambit of the RFA. *Am. Trucking Ass'ns v. EPA*, 175 F.3d 1027, 1044 (D.C. Cir. 1999), *aff'd in part and rev'd in part on other grounds*, *Whitman v. Am. Trucking Ass'ns*, 531 U.S. 457 (2001); *Mid-Tex Elec. Coop. v. FERC*, 773 F.2d 327, 342-43 (D.C. Cir. 1985) ("Congress did not intend to require that every agency consider every indirect effect that any regulation might have on small businesses in any stratum of the national economy.").

APPENDIX

List of Petitioners

Abbreviation	**Petitioner**
CAISO	California Independent System Operator Corporation
Competitive Power Suppliers (CSA)	Electric Power Supply Association Independent Power Producers of New York, Inc. Electric Power Generation Association New England Power Generators Association, Inc.
CPUC	Public Utilities Commission of the State of California
DR Supporters	Demand Response Supporters (members include American Forest & Paper Association, Consumer Demand Response Initiative, EnerNOC, Inc., Project for Sustainable FERC Energy Policy, and Viridity Energy, Inc.)
EEI	Edison Electric Institute
ICC	Illinois Commerce Commission

Abbreviation	Petitioner
Joint Parties	American Public Power Association National Rural Electric Cooperative Association Old Dominion Electric Cooperative
Joint Petitioners	Electric Power Supply Association American Public Power Association Electric Power Generation Association National Rural Electric Cooperative Association
Midwest ISO TOs	Midwest ISO Transmission Owners
Midwest TDUs	Midwest Transmission Dependent Utilities
OMS	Organization of MISO States
P3	PJM Power Providers Group
PPL Parties	PPL Parties
SWP	California Department of Water Resources State Water Project

Parties Filing Answers

Abbreviation	**Petitioner**
IECG	Industrial Energy Consumer Group
ISO-NE	ISO New England Inc.
NEPOOL Participants Committee	New England Power Pool Participants Committee
Occidental	Occidental Permian Ltd. Occidental Chemical Corporation
Viridity	Viridity Energy, Inc.

MOELLER, Commissioner, *dissenting*:

Demand response plays a very important role in markets by providing significant economic, reliability, and other market-related benefits when properly deployed.

However, it has become clear since the issuance of Order No. 745 that my earlier concerns in this proceeding were justified.[217] Namely, rather than impose a nationwide approach to demand response compensation, the Commission's objective of promoting demand response would have been better served if the regions were free to propose compensation methods that recognize the very real differences in the structures of the regional markets. In addition, the evidence now shows that the Net Benefits Test will be so costly to develop and so difficult to administer that it can be expected to result in an allocation of the costs of demand response to the parties that do not benefit from demand response.[218] Therefore, rather than continuing to pursue demand response compensation at full LMP only when the Net Benefits Test is passed, I would have changed that decision and put in its place compensation at LMP—G, where "G" is the avoided retail cost of generation.

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[217] *Demand Response Compensation in Organized Wholesale Energy Markets*, 134 FERC ¶ 61,187 (2011) (*Moeller Dissenting*) ("Order No. 745").

[218] *See e.g.*, Requests for Rehearing, PJM Power Providers Group (P3) at 12; Organization of MISO States (OMS) at 4; California Department of Water Resources State Water Project (SWP) at 4-7; Old Dominion Electric Cooperative (ODEC), American Public Power Association (APPA), National Rural Electric Cooperative Association (NRECA) at 23-25; PPL Parties at 15-16.

While consumers may pay lower rates if some consumers voluntarily agree to use less electricity, the Federal Power Act requires this Commission to establish just and reasonable rates that are not discriminatory.[219] If the Commission requires the RTOs and ISOs to overcompensate for providing demand response, the resulting rates are both discriminatory and not just and reasonable.

The Case Has Not Been Made

Both the Final Rule and the current rehearing order fail to justify the imposition of a national standard for demand response compensation. Rather than address the legitimate concerns that were raised in this proceeding[220] about (1) the difficulties with implementing this rule and (2) the disruptions to existing demand response programs, this order simply refers to the individual RTO and ISO compliance proceedings—as if these problems were not fundamental to the viability of the rule.

As I recognized in my earlier dissent in this proceeding, organized markets have already demonstrated that they can develop demand response compensation rules. RTOs and ISOs have been working with their market participants through stakeholder processes to design demand response compensation rules that are tailored to suit the needs of their individual energy markets. I would have allowed these efforts to continue. However, despite

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[219] 16 U.S.C. § 824d (2006).

[220] *See e.g.*, Requests for Rehearing, Midwest ISO Transmission Owners at 3; CAISO at 1-2; Edison Electric Institute (EEI) at 3; Competitive Power Supplier Associations (CSA) at 3; ODEC, APPA, NRECA at 5-11.

warnings about disruptions from some parties,[221] the majority is proceeding with generic rules that may actually discourage demand response products.

Furthermore, I would have accepted the Motion to Lodge submitted by CAISO[222] and do not believe that sufficient rationale was given for denying the motion in this proceeding.[223] The majority claims the request was made out-of-time, despite CAISO's internal procedures that require draft opinions to be posted before they are finalized. The motion by CAISO and its Market Surveillance Committee illustrates many of the difficulties stakeholders are having with their efforts to comply with this rule. By rejecting the motion, the majority did not counter the litany of arguments that assailed the workability of the final rule in CAISO.

The Net Benefits Test

As currently presented, the Net Benefits Test uses backward looking data to predict market rates a year later, when thousands of variables related to economic conditions and weather will surely result in different market rates and conditions. Therefore, it cannot define the benefits of demand response with any accuracy. As a consequence, the costs of demand response compensation will necessarily be inaccurate, and therefore, not just and reasonable. To be clear, I do not fault the RTOs and ISOs and their stakeholders

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[221] *See* California Independent System Operator Corporation (CAISO), Request for Rehearing, April 14, 2011 at 5, 29. See also Affidavit of Peter Scala on behalf of the California Public Utilities Commission (CPUC).

[222] CAISO, Motion to Lodge, June 17, 2011 and Errata, June 22, 2011.

[223] Order No. 745-A at P 9-10.

who are trying to develop this unwieldy test. The difficulties inherent in developing a Net Benefits Test will be present regardless of whether the test for benefits is conducted dynamically[224] or statically.

However, instead of acknowledging the overwhelming opposition—often by the very stakeholders tasked with developing the Net Benefits Test—the majority points to the fact that required compliance filings have been submitted and avoids addressing the substantive arguments about whether the Net Benefits Test is actually workable.[225]

Moreover, this order should have evaluated the costs of compliance, including the development of a static Net Benefits Test as well as studying and reporting on the development of a dynamic Net Benefits Test.[226]

While I would have preferred to allow the regions to continue to develop their own demand response compensation programs, absent that outcome, using

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[224] The unchallenged evidence in this case is that, "the ISO is unaware of a technological solution that exists and there is no reason to believe that it is practically possible for the ISO to incorporate a dynamic net benefits test as part of the ISO's optimization in the foreseeable future." *See* CAISO, Request for Rehearing at 40-41. See also Declaration of Khaled Abdul-Rahman on behalf of the California Independent System Operator Corporation.

[225] Order No. 745-A at P 93.

[226] Order No. 745-A at P 84. "The Commission required each ISO and RTO to conduct a study to determine whether the net benefits test could be integrated into its dispatch. Those studies are required to be filed by September 2, 2012."

LMP—G would have at least negated the need to develop and conduct the Net Benefits Test.[227]

Demand Response Compensation

The order continues to effectively find that demand resources being compensated at the *value* of full LMP is not enough, so instead requires that demand resource be *paid* the full LMP *plus* be allowed to retain the savings associated with its avoided retail generation cost. Plainly speaking, this is over-compensation to demand response resources. And overcompensation cannot be just and reasonable. The majority insists that demand response is "comparable" to generation, and therefore, deserves the same amount and type of compensation as generation.[228] However, commenters have noted that by not accounting for the contributions of behind-the-meter generation, some demand response resources will receive a rate equal to double the LMP rate.[229] Nothing

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[227] "No such test would be necessary if instead a payment of LMP-G was made to fully verified DR. Genuine DR that can be profitable under this payment is efficient (increases market surplus) while any DR that cannot make money under that price reduces market surplus. With the correct payment, no separate screen, such as the Order's benefit-cost test, is needed." *See* CAISO Motion to Lodge, June 22, 2011, Exhibit A, "Opinion on Economic Issues Raised by FERC Order 745" at 12.

[228] *See* Order No. 745-A at P 56.

[229] "For example, Severstal Steel's Sparrows Point plant purchases its electricity directly from PJM's day-ahead and real-time markets. The plant has a peak load of 230 MW and has 150 MW of [behind-the-meter generation] that it uses to reduce its purchases when PJM's LMPs are greater than the running costs of its own generation. Clearly, Severstal Steel's generators are directly competing with wholesale generators in the PJM footprint but they are being compensated exactly twice LMP for the energy that the wholesale generators can produce at half that

distinguishes a generator that is behind-the-meter from one that is in front-of-the-meter such that it is just and reasonable to pay one generator double the rate that is paid to another.

Because measurement and verification is essential to the integrity and effectiveness of demand response compensation,[230] it should have been more directly addressed in this order. Commenters raise valid concerns about the current lack of effective measurement and verification standards, and about the cost and time needed to develop these standards.[231] The order dismisses these concerns and passes off this challenge to the RTOs and ISOs to figure out measurement and verification in their compliance proceedings without regard to the costs of developing these programs.

For the reasons given, I cannot support this order as it violates the Commission's statutory mandate to ensure supplies of electric energy at just, reasonable, and not unduly discriminatory or preferential rates.

Philip D. Moeller
Commissioner

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price. Paying one generator twice the price that is paid to another generator for delivering an identical, fungible product is clearly unduly discriminatory." Request for Rehearing, EEI at 21 (footnote omitted).

[230] *See* Order No. 745 at P 93. *See also* Order No. 745-A at P 123.

[231] *See* Request for Rehearing, Midwest TDUs at 15. *See also* Request for Rehearing, CSA at 66-70. " . . . the Commission's decision to adopt the Final Rule, before meaningful measurement and verification standards have been developed, was arbitrary and capricious. The evidence in the record unequivocally indicates that current NAESB standards and ISO/RTO rules cannot prevent fraud and abuse."

APPENDIX C

FEDERAL ENERGY REGULATORY COMMISSION
Commission Opinions, Orders and Notices

Docket No. RM10-17-000
ORDER NO. 745
(Issued March 15, 2011)

Demand Response Compensation in Organized Wholesale Energy Markets

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FINAL RULE

Before Commissioners: Jon Wellinghoff, Chairman; Marc Spitzer, Philip D. Moeller, John R. Norris, and Cheryl A. LaFleur.

I. Introduction

1. This Final Rule addresses compensation for demand response in Regional Transmission Organization (RTO) and Independent System Operator (ISO) organized wholesale energy markets, i.e., the day-ahead and real-time energy markets. As the Commission has previously recognized, a market functions effectively only when both supply and demand can meaningfully participate. The Commission, in the Notice of Proposed Rulemaking (NOPR) issued in this proceeding on March 18, 2010, proposed a remedy to concerns that current compensation levels

inhibited meaningful demand-side participation.[1] After nearly 3,800 pages of comments, a subsequent technical conference, and the opportunity for additional comment, we now take final action.

2. We conclude that when a demand response[2] resource[3] participating in an organized wholesale energy market[4] administered by an RTO or ISO has the capability to balance supply and demand as an alternative to a generation resource and when dispatch of that demand response resource is cost-effective as determined by the net benefits test described herein, that demand response resource must be compensated for the service it provides to the energy market at the market price for energy, referred

[1] *Demand Response Compensation in Organized Wholesale Energy Markets*, Notice of Proposed Rulemaking, 75 FR 15362 (Mar. 29, 2010), FERC Stats. & Regs. ¶ 32,656 (2010) (NOPR).

[2] 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. 18 CFR 35.28(b)(4) (2010).

[3] Demand response resource means a resource capable of providing demand response. 18 CFR 35.28(b)(5).

[4] The requirements of this final rule apply only to a demand response resource participating in a day-ahead or real-time energy market administered by an RTO or ISO. Thus, this Final Rule does not apply to compensation for demand response under programs that RTOs and ISOs administer for reliability or emergency conditions, such as, for instance, Midwest ISO's Emergency Demand Response, NYISO's Emergency Demand Response Program, and PJM's Emergency Load Response Program. This Final Rule also does not apply to compensation in ancillary services markets, which the Commission has addressed elsewhere. *See*, *e.g.*, *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, 73 FR 64100 (Oct. 28, 2008), FERC Stats. & Regs. ¶ 31,281 (2008) (Order No. 719).

to as the locational marginal price (LMP).[5] The Commission finds that this approach to compensation for demand response resources is necessary to ensure that rates are just and reasonable in the organized wholesale energy markets. Consistent with this finding, this Final Rule adds section 35.28(g)(1)(v) to the Commission's regulations to establish a specific compensation approach for demand response resources participating in the organized wholesale energy markets administered by RTOs and ISOs. The Commission is not requiring the use of this compensation approach when demand response resources do not satisfy the capability and cost-effectiveness conditions noted above.[6]

3. This cost-effectiveness condition, as determined by the net benefits test described herein, recognizes that, depending on the change in LMP relative to the size of the energy market, dispatching demand response resources may result in an increased cost per unit ($/MWh) to the remaining wholesale load associated with the decreased amount of load paying the bill. This is the case because customers are billed for energy based on the units, MWh, of electricity consumed. We refer to this potential result as the billing unit effect of dispatching demand response. By

[5] LMP refers to the price calculated by the ISO or RTO at particular locations or electrical nodes or zones within the ISO or RTO footprint and is used as the market price to compensate generators. There are variations in the way that RTOs and ISOs calculate LMP; however, each method establishes the marginal value of resources in that market. Nothing in this Final Rule is intended to change RTO and ISO methods for calculating LMP.

[6] The Commission's findings in this Final Rule do not preclude the Commission from determining that other approaches to compensation would be acceptable when these conditions are not met.

contrast, dispatching generation resources does not produce this billing unit effect because it does not result in a decrease of load. To address this billing unit effect, the Commission in this Final Rule requires the use of the net benefits test described herein to ensure that the overall benefit of the reduced LMP that results from dispatching demand response resources exceeds the cost of dispatching and paying LMP to those resources. When the net benefits test described herein is satisfied and the demand response resource clears in the RTO's or ISO's economic dispatch, the demand response resource is a cost-effective alternative to generation resources for balancing supply and demand.

4. To implement the net benefits test described herein, we direct each RTO and ISO to develop a mechanism as an approximation to determine a price level at which the dispatch of demand response resources will be cost-effective. The RTO or ISO should determine, based on historical data as a starting point and updated for changes in relevant supply conditions such as changes in fuel prices and generator unit availability, the monthly threshold price corresponding to the point along the supply stack beyond which the overall benefit from the reduced LMP resulting from dispatching demand response resources exceeds the cost of dispatching and paying LMP to those resources. This price level is to be updated monthly, by each ISO or RTO, as the historic data and relevant supply conditions change.[7]

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[7] In its compliance filing an RTO or ISO may attempt to show, in whole or in part, how its proposed or existing practices are consistent with or superior to the requirements of this Final Rule.

5. This Final Rule also sets forth a method for allocating the costs of demand response payments among all customers who benefit from the lower LMP resulting from the demand response.

6. The tariff changes needed to implement the compensation approach required in this Final Rule, including the net benefits test, measurement and verification explanation and proposed changes, and the cost allocation mechanism must be made on or before July 22, 2011. All tariff changes directed herein should be submitted as compliance filings pursuant to this Final Rule, not pursuant to section 205 of the Federal Power Act (FPA).[8] Accordingly, each RTO's or ISO's compliance filing to this Final Rule will become effective prospectively from the date of the Commission order addressing that filing, and not within 60 days of submission.

7. In addition, we believe that integrating a determination of the cost-effectiveness of demand response resources into the dispatch of the ISOs and RTOs may be more precise than the monthly price threshold and, therefore, provide the greatest opportunity for load to benefit from participation of demand response in the organized wholesale energy market administered by an RTO or ISO. However, we acknowledge the position of several of the RTOs and ISOs that modification of their dispatch algorithms to incorporate the costs related to demand response may be difficult in the near term. In light of those concerns, we require each RTO and ISO to undertake a study examining the requirements for and impacts of implementing a dynamic approach which incorporates the billing unit effect in the dispatch algorithm to determine when

[8] 16 U.S.C. 824d (2006).

paying demand response resources the LMP results in net benefits to customers in both the day-ahead and real-time energy markets. The Commission directs each RTO and ISO to file the results of this study with the Commission on or before September 21, 2012.[9]

II. Background

8. Effective wholesale competition protects customers by, among other things, providing more supply options, encouraging new entry and innovation, and spurring deployment of new technologies.[10] Improving the competitiveness of organized wholesale energy markets is therefore integral to the Commission fulfilling its statutory mandate under the FPA to ensure supplies of electric energy at just, reasonable, and not unduly discriminatory or preferential rates.[11]

9. As the Commission recognized in Order No. 719, active participation by customers in the form of demand response in organized wholesale energy markets helps to increase competition in those markets.[12] Demand response, whereby customers reduce electricity consumption from normal usage

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[9] We note that this report is for informational purposes only and will neither be noticed nor require Commission action.

[10] *See*, *e.g*., *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, 73 FR 64100 (Oct. 28, 2008), FERC Stats. & Regs. ¶ 31,281, at P 1 (2008) (Order No. 719); *see also Regional Transmission Organizations*, Order No. 2000, FERC Stats. & Regs. ¶ 31,089, at P 1 (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, 348 U.S. App. D.C. 205 (D.C. Cir. 2001).

[11] 16 U.S.C. 824d (2006); Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 1.

[12] *See* Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 48.

levels in response to price signals, can generally occur in two ways: (1) customers reduce demand by responding to retail rates that are based on wholesale prices (sometimes called "price-responsive demand"); and (2) customers provide demand response that acts as a resource in organized wholesale energy markets to balance supply and demand. While a number of states and utilities are pursuing retail-level price-responsive demand initiatives based on dynamic and time-differentiated retail prices and utility investments in demand response enabling technologies, these are state efforts, and, thus, are not the subject of this proceeding. Our focus here is on customers or aggregators of retail customers providing, through bids or self-schedules, demand response that acts as a resource in organized wholesale energy markets.

10. As the Commission stated in Order No. 719,[13] and emphasized in the NOPR,[14] there are several ways in which demand response in organized wholesale energy markets can help improve the functioning and competitiveness of those markets. First, when bid directly into the wholesale market, demand response can facilitate RTOs and ISOs in balancing supply and demand, and thereby, help produce just and reasonable energy prices.[15] This is because customers

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[13] *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719-A, FERC Stats. & Regs. ¶ 31,292, at P 48 (2009).

[14] NOPR, FERC Stats. & Regs. ¶ 32,656 at P 4.

[15] For example, a study conducted by PJM, which simulated the effect of demand response on prices, demonstrated that a modest three percent load reduction in the 100 highest peak hours corresponds to a price decline of six to 12 percent. ISO-RTO Council Report, Harnessing the Power of Demand How RTOs and ISOs Are Integrating Demand Response into Wholesale Electricity Markets, found at http://www.isorto.org/atf/cf/#5B4

who choose to respond will signal to the RTO or ISO and energy market their willingness to reduce demand on the grid which may result in reduced dispatch of higher-priced resources to satisfy load.[16] Second, demand response can mitigate generator market power.[17] This is because the more demand response that sees and responds to higher market prices, the greater the competition, and the more downward pressure it places on generator bidding strategies by increasing the risk to a supplier that it will not be dispatched if it bids a price that is too high.[18] Third, demand response has the potential to support system reliability and address resource adequacy[19] and resource management challenges surrounding the unexpected loss of generation. This is because demand

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E85C6-7EAC-40A0-8DC3-003829518EBD'/IRC_DR_Report_101607.pdf.

[16] *Id*. ("Demand response tends to flatten an area's load profile, which in turn may reduce the need to construct and use more costly resources during periods of high demand; the overall effect is to lower the average cost of producing energy.").

[17] *See* Comments of NYISO's Independent Market Monitor filed in Docket No. ER09-1142-000, May 15, 2009 (Demand response "contributes to reliability in the short-term, resource adequacy in the long-term, reduces price volatility and other market costs, and mitigates supplier market power.").

[18] *Id*.

[19] *See* ISO-RTO Council Report, Harnessing the Power of Demand How RTOs and ISOs Are Integrating Demand Response into Wholesale Electricity Markets at 4, found at http://www.isorto.org/atf/cf/#5B4E85C6-7EAC-40A0-8DC3-003829518EBD'/IRC_DR_Report_101607.pdf ("Demand response contributes to maintaining system reliability. Lower electric load when supply is especially tight reduces the likelihood of load shedding. Improvements in reliability mean that many circumstances that otherwise result in forced outages and rolling blackouts are averted, resulting in substantial financial savings. . . .").

response resources can provide quick balancing of the electricity grid.[20]

11. Congress has recognized the importance of demand response by enacting national policy requiring its facilitation.[21] Consistent with that policy, the Commission has undertaken several reforms to support competitive wholesale energy markets by removing barriers to participation of demand response resources. For example, in Order No. 890, the Commission modified the *pro forma* Open Access Transmission Tariff to allow non-generation resources, including demand response resources, to be used in the provision of certain ancillary services where appropriate on a comparable basis to service provided by generation resources.[22] Order No. 890-A

[20] For instance, in ERCOT, on February 26, 2008, through a combination of a sudden loss of thermal generation, drop in power supplied by wind generators, and a quicker-than-expected ramping up of demand, ERCOT found itself short of reserves. The system operator called on all demand response resources, and 1200 MW of Load acting as Resource (LaaRs) responded quickly, bringing ERCOT back into balance. OAK RIDGE NAT'L LAB., NAT'L RENEWABLE ENERGY LAB., TECH. REP. NREL/TP-500-43373, ERCOT EVENT ON FEB. 26, 2008: LESSONS LEARNED (JUL. 2008).

[21] *See* Energy Policy Act of 2005, Pub. L. No. 109-58, § 1252(f), 119 Stat. 594, 965 (2005) ("It is the policy of the United States that . . . unnecessary barriers to demand response participation in energy, capacity, and ancillary service markets shall be eliminated.").

[22] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241, at P 887-88 (2007), *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g and clarification*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228 (2009), *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

further required transmission providers to develop transmission planning processes that treat all resources, including demand response, on a comparable basis.[23]

12. In Order No. 719, the Commission required RTOs and ISOs to, among other things, accept bids from demand response resources in their markets for certain ancillary services on a basis comparable to other resources.[24] The Commission also required each RTO and ISO "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,"[25] for purposes of encouraging existing generation and demand resources to continue to be relied upon during an operating reserve shortage, and encouraging entry of new generation and demand resources.[26]

13. Additionally, in recent years several RTOs and ISOs have instituted various types of demand response programs. While some of these programs are administered for reliability and emergency conditions, other programs allow wholesale customers, qualifying large retail customers, and aggregators of retail customers to participate directly in the day-ahead and real-time energy markets, certain ancillary service markets and capacity markets.[27]

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[23] Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 at P 216.

[24] Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 47-49.

[25] Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 194.

[26] Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 247.

[27] Other demand response programs allow demand response to be used as a capacity resource and as a resource during system emergencies or permit the use of demand response for synchronized reserves and regulation service. *See*, *e.g.*, *PJM*

14. To date, the Commission has allowed each RTO and ISO to develop its own compensation methodologies for demand response resources participating in its day-ahead and real-time energy markets. As a result, the levels of compensation for demand response vary significantly among RTOs and ISOs.[28] For example, PJM Interconnection, L.L.C. (PJM) pays the LMP minus the generation and transmission portions of the retail rate.[29] ISO New England Inc. (ISO-NE) and New York Independent System Operator, Inc. (NYISO) pay LMP when prices exceed a threshold level, with the levels differing between the RTOs.[30]

Interconnection, L.L.C., 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 (D.C. Cir. 2007); *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, L.L.C.*, 99 FERC ¶ 61,227 (2002); *California Independent System Operator Corp.*, 132 FERC ¶ 61,045 (2010).

[28] *See New England, Inc.*, Docket No. ER09-1051-000; *ISO New England, Inc.*, Docket No. ER08-830-000; *Midwest Indep. Transmission Sys. Operator, Inc.*, Docket No. ER09-1049-000.

[29] *See* sections 3.3A.4 and 3.3A.5 (Market Settlements in the Real-Time and Day-Ahead Energy Markets) of the Appendix to Attachment K of the PJM Tariff.

[30] For example, under ISO-NE's Real-Time Price Response Program, the minimum bid is $100/MWh and a demand response resource is paid the higher of LMP or $100/MWh. For the Day-Ahead Load Response Program, the minimum offer level is calculated on a monthly basis and is the Forward Reserve Fuel Index ($/MMBtu) multiplied by an effective heat rate of 11.37 MMBtu/MWh. The maximum offer level is $1,000/MWh. *See* sections III.E.2.1 and III.E.3.2 of Appendix E of the ISO New

The Midwest Independent Transmission System Operator, Inc.'s (Midwest ISO) demand response programs[31] pay LMP for demand response resources in the day-ahead and real-time energy markets.[32] The California Independent System Operator Corporation (CAISO) pays LMP at pricing nodes, or sub-load aggregation points (Sub-LAP) in its Proxy Demand Resource program that allows qualifying resources to provide day-ahead and real-time energy.[33] CAISO also provides for demand response resources to participate in its Participating Load program, which enables certain resources to provide curtailable demand in the CAISO market. CAISO pays nodal real-time LMP for its Participating Load program. The Southwest Power Pool, Inc. (SPP) has filed revisions to its tariff to

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England Transmission, Markets and Services Tariff. NYISO implements a day-ahead demand response program by which resources bid into the market at a minimum of $75/MWh and can get paid the LMP. *See* section 4.2.2.9 ("Day-Ahead Bids from Demand Reduction Providers to Supply Energy from Demand Reductions") of NYISO's Market Services Tariff.

[31] Midwest ISO FERC Electric Tariff characterizes Demand Response Resources (DRR) as either DRR-Type I or DRR-Type II. DRR-Type I are capable of supplying a specific quantity of energy or contingency reserve through physical load interruption. DRR-Type II are capable of supplying energy and/or operating reserves over a dispatchable range. *See* sections 39.2.5A and 40.2.5 of the Tariff.

[32] *See* Charges and Payments for Purchases and Sales for Demand Response Resources. Midwest ISO FERC Electric Tariff, section 39.3.2C.

[33] *See* section 11.2.1.1 IFM Payments for Supply of Energy, CAISO FERC Electric Tariff. CAISO notes that for a Proxy Demand Resource that is made up of aggregated loads, the Resource is paid the weighted average of the LMPs of each pricing node where the underlying aggregate loads reside. *See CAISO*, 132 FERC ¶ 61,045, at P 26 n.14 (2010).

facilitate demand response in the Energy Imbalance Service Market.[34]

III. Procedural History

15. As noted above, the Commission issued the NOPR in this proceeding on March 18, 2010.[35] The NOPR proposed to require RTOs and ISOs to pay the LMP in all hours for demand reductions made in response to price signals. The Commission sought comments on the compensation proposal and, in particular, on the comparability of generation and demand response resources; alternative approaches to compensating demand response in organized wholesale energy markets; whether payment of LMP should apply in all hours, and, if not, any criteria that should be used for establishing hours when LMP should apply; and whether to allow for regional variations concerning approaches to demand response compensation.[36]

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[34] The Commission has directed SPP to report on ways it can incorporate demand response into its imbalance market. *Southwest Power Pool, Inc*., 128 FERC ¶ 61,085 (2009). As of September 1, 2010, SPP has submitted seven informational status reports regarding its efforts to address issues related to demand response resources. In orders addressing SPP's compliance with Order No. 719, the Commission also directed SPP to make another compliance filing addressing demand response participation in its organized markets. *Southwest Power Pool, Inc*., 129 FERC ¶ 61,163, at P 51 (2009). On May 19, 2010, SPP submitted revisions to its Open Access Transmission Tariff in Docket Nos. ER09-1050-004 and ER09-748-002 to comply with the Commission's requirements established in Order Nos. 719 and 719-A. These filings are pending before the Commission.

[35] NOPR, FERC Stats. & Regs. ¶ 32,656.

[36] *See* Appendix for a list of commenters.

16. After receiving the first round of comments, the Commission issued a Supplemental Notice of Proposed Rulemaking and Notice of Technical Conference (Supplemental NOPR) in this proceeding on August 2, 2010.[37] The Supplemental NOPR sought additional comment on: whether the Commission should adopt a net benefits test for determining when to compensate demand response providers, and, if so, what, if any, requirements should apply to the methods for determining net benefits; and what, if any, requirements should apply to how the costs of demand response are allocated. The Commission further directed Staff to hold a technical conference focused on these two issues, which occurred on September 13, 2010.[38]

IV. Discussion

17. Based upon the record in this proceeding, the Commission herein requires greater uniformity in compensating demand response resources participating in organized wholesale energy markets. This Final Rule also addresses the allocation of costs resulting from the commitment of demand response, directing that such costs be allocated among those customers who benefit from the lower LMP resulting from the demand response.

A. Compensation Level

1. NOPR Proposal

18. The NOPR proposed to require RTOs and ISOs to pay the LMP in all hours for demand reductions

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[37] *Supplemental Notice of Proposed Rulemaking and Notice of Technical Conference*, 75 FR 47499 (Aug. 6, 2010), 132 FERC ¶ 61,094 (2010) (Supplemental NOPR).

[38] *See* Notice of Technical Conference (Aug. 27, 2010).

made in response to price signals. The NOPR sought to provide comparable compensation to generation and demand response providers, based on the premise that both resources provide a comparable service to RTOs and ISOs for purposes of balancing supply and demand and maintaining a reliable electricity grid.[39] Also as stated in the NOPR, the proposed compensation level was designed to allow more demand response resources to cover their investment costs in demand response-related technology (such as advanced metering) and thereby facilitate their ability to participate in organized wholesale energy markets.[40] The Commission sought comments on the compensation proposal and, in particular, on the comparability of generation and demand response resources; alternative approaches to compensating demand response in organized wholesale energy markets; whether payment of LMP should apply in all hours, and, if not, any criteria that should be used for establishing hours when LMP should apply; and whether to allow for regional variations concerning approaches to demand response compensation.

19. In the Supplemental NOPR, the Commission sought additional comments and directed staff to hold a technical conference regarding various net benefits tests. In particular, the Commission sought comment on: whether the Commission should adopt a net benefits test applicable in all or only some hours and what the criteria of any such test would be; how to define net benefits; what costs demand response providers and load serving entities incur and whether they should be included in a net benefits test; whether

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[39] NOPR, FERC Stats. & Regs. ¶ 32,656 at P 15.

[40] *Id*. at P 16.

any net benefits methodology adopted should be the same for all RTOs and ISOs; proposed methodologies for implementing a net benefits test and the advantages and limitations of any proposed methodologies.[41] The September 13, 2010 Technical Conference included an eleven-member panel discussion of net benefits tests representing a wide range of interests and viewpoints.[42] The Commission subsequently received additional written comments addressing these issues.

2. Comments

a) Capability of Demand Response and Generation Resources to Balance Energy Markets

20. Various commenters address the comparability of demand response and generation resources for purposes of compensation in the organized wholesale energy markets. To begin, numerous commenters address the physical or functional comparability of demand response and generation, agreeing that an increment of generation is comparable to a decrement of load for purposes of balancing supply and demand in the day-ahead and real-time energy markets.[43] Equating generation and demand response resources, Dr. Alfred E. Kahn states:

> [Demand response] is in all essential respects economically equivalent to supply response. . . [so] economic efficiency requires. . . that it should be

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[41] Supplemental NOPR, 132 FERC ¶ 61,094 at P 8-9.

[42] *See* Sept. 13, 2010 Tr.

[43] DR Supporters Aug. 30, 2010 Comments (Kahn Affidavit at 2); Verso May 13, 2010 Comments at 3-4; Occidental May 13, 2010 Comments at 11; Viridity June 18, 2010 Comments at 5.

> rewarded with the same LMP that clears the market. Since [demand response] is actually—and not merely metaphorically—equivalent to supply response, economic efficiency requires that it be regarded and rewarded, equivalently, as a resource proffered to system operators, and be treated equivalently to generation in competitive power markets. That is, all resources—energy saved equivalently to energy supplied—. . . should receive the same market-clearing LMP in remuneration.[44]

Indeed, some commenters believe that, from a physical standpoint, demand response can provide superior services to generation, such as providing a quick response in meeting system requirements and service without having to construct major new facilities.[45] Occidental asserts that the fungibility of demand response and generation output creates greater operational flexibility that, in turn, offers RTOs and ISOs multiple options to solve system issues both in energy and ancillary service markets, and that the fungible nature of demand response and generation supports comparable compensation for each as proposed in the NOPR.[46]

21. Viridity states that attempts to distinguish the physical characteristics of generation and demand response ignore bid-based security-constrained economic dispatch as the foundation for LMP and are based on the assumption that the value of load

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[44] DR Supporters August 30, 2010 Reply Comments (Kahn Affidavit at 2 (footnote omitted)).

[45] Verso May 13, 2010 Comments at 3-4; Alcoa May 13, 2010 Comments at 9.

[46] Occidental May 13, 2010 Comments at 11.

management on the grid is limited to periods when the system is stressed, i.e., traditional "super peak shaving." Viridity states that, while these arguments might have been valid 15 years ago, today competitive markets can offer proactively-managed load control and comparable and non-discriminatory treatment of load-based energy resources. Therefore, Viridity asserts that all resources should be paid LMP if the grid operator accepts their bid to achieve grid balance.[47]

22. At the same time, other commenters argue that generation and demand response are not physically equivalent, pointing out that demand response reduces consumption, whereas generators serve consumption.[48] They argue that a MW reduction in demand does not turn on the lights.[49] EPSA adds that a load reduction does not provide electrons to any other load and, instead, allows the marginal electron to serve a different customer.[50] Some commenters assert that a power system can function solely and reliably on generating plants and without any reliance on demand response, while the system cannot rely exclusively on demand response because demand response by itself cannot keep the lights on. Ultimately, some commenters point out, megawatts produced by generators need to be placed on the system in order for power to flow.[51] Battelle additionally argues that a reduction in consumption is

[47] Viridity June 18, 2010 Comments at 5.

[48] ISO-NE May 13, 2010 Comments at 3.

[49] *See*, *e.g*., APPA May 13, 2010 Comments at 12; Capital Power May 13, 2010 Comments at 2.

[50] EPSA May 13, 2010 Comments at 72.

[51] *See*, *e.g*., PSEG May 13, 2010 Comments at 8.

not exactly the same as an increase in production, because elastic demand often comes with attendant future consequences, such as rebound, by virtue of substitution in time.[52]

23. Some commenters who argue that the physical characteristics of demand response are not comparable to generation frame their arguments in terms of the ability of the system operator to call on demand response and generation resources to provide balancing energy. They argue that generation resources provide superior service to demand response providers, positing that demand response is not intended for long periods of balancing needs,[53] and that, moreover, contracts with demand response providers limit the number of hours and times a customer may be called upon to curtail. For example, ODEC asserts that the degree of physical comparability depends on the extent to which demand response resources can be dispatched similar to a generator.[54] Calpine adds that traditional generators provide system support features that demand response cannot, such as ancillary services including governor response or reactive power voltage support, which are necessary for reliable operation of the electric system.[55]

24. Numerous commenters also address the comparability of demand response and generation in economic terms. For example, EEI states that, in finance terms, the demand response product is, unlike generation, essentially an unexercised call option on

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[52] Battelle May 13, 2010 Comments at 3.

[53] AEP May 13, 2010 Comments at 7-8.

[54] ODEC May 13, 2010 Comments at 12.

[55] Calpine May 13, 2010 Comments at 4-5.

spot market energy, and the value of that option is well-established in finance theory as the value of the resource (LMP) minus the "strike price," which EEI contends in this case is the retail tariff rate.[56] EEI and like-minded commenters support, therefore, alternative compensation for demand response to equal LMP minus the generation (or G) component of the retail rate.[57] They posit that payment of LMP without an offset for some portion of the retail rate does not send the proper economic signal to providers of demand response, because it fails to take into account the retail rate savings associated with demand response, and thereby overcompensates the demand response provider. As described by Dr. William W. Hogan on behalf of EPSA, this is sometimes called a double-payment for demand reductions, because demand response providers would "receive" both the cost savings from not consuming an increment of electricity at a particular price, plus an

[56] EEI May 13, 2010 Comments at 4-5. *See also* Robert L. Borlick May 13, 2010 Comments at 4. Mr. Borlick argues that the correct price is LMP minus the Marginal Foregone Retail Rate (MFRR), describing the economically efficient price that should be paid to a demand response provider as "its offer price minus the price in its retail tariff at which it would have purchased the curtailed energy." Mr. Borlick asserts that this amount accurately represents the forgone opportunity costs that result when a demand response provider reduces its load. *Id*.

[57] *See* May 13, 2010 Comments of: APPPA; AEP; The Brattle Group; Calpine; ConEd; Consumers Energy; CPG; Detroit Edison; Direct Energy; Dominion; Duke Energy; Edison Mission; EEI; EPSA; Exelon; FTC; GDF; NYISO on behalf of the ISO RTO Council; ICC; IPPNY; Indicated New York TOs; IPA; ISO-NE; Midwest TDUs; Mirant; Midwest ISO TOs; NEPGA; NYISO; ODEC; OMS; PJM; PJM IMM; P3; Potomac Economics; PG&E; Ohio Commission; Robert L. Borlick; Roy Shanker; and RRI Energy.

LMP payment for not consuming that same increment of electricity.[58] Viewing LMP as a double-payment, these commenters argue that paying LMP will result in more demand response than is economically efficient.[59] For example, Dr. Hogan states that paying LMP might motivate a company to shut down even though the benefits of consuming electricity outweigh the cost at LMP.[60] Indeed, P3 argues that compensation in excess of LMP-G is unjust and unreasonable, because such a payment level imposes costs on customers that are not commensurate with benefits received.[61]

25. ISO-NE argues that paying full LMP to demand response providers without taking into account the bill savings produced by demand response provides a significant financial incentive to dispatch demand response with marginal costs exceeding LMPs. By dispatching higher-cost demand response, ISO-NE

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[58] *See* Attachment to Answer of EPSA, Providing Incentives for Efficient Demand Response, Dr. William W. Hogan, Oct. 29, 2009, submitted in Docket No. EL09-68-000.

[59] EPSA May 13, 2010 Comments at 23. *See also* May 13, 2010 Comments of APPA at 13; FTC at 9; Midwest TDUs at 14; Mirant at 2; New York Commission at 5; PJM at 6; PSEG at 5; and Potomac Economics at 6-8.

[60] Attachment to Answer of EPSA, Providing Incentives for Efficient Demand Response, Dr. William W. Hogan, Oct. 29, 2009, submitted in Docket No. EL09-68-000. In Dr. Hogan's view, supply should produce when the price of electricity exceeds its cost of production and demand should decline to consume when the costs in terms of convenience of delaying use are less than the price of electricity.

[61] P3 June 14, 2010 Comments at 2, 7-8.

asserts, lower-cost generation resources are displaced.[62] At the same time, ISO-NE argues, generation is not dispatched and paid for only when the generation reduces LMP—generation is dispatched and paid for when it is cost-effective.[63]

26. Dr. Hogan further disputes arguments equating a MW of energy supplied to a MW of energy saved on economic grounds. Dr. Hogan draws a distinction between reselling something that one has purchased, and selling something that one would have purchased without actually purchasing it. Dr. Hogan argues that from the perspective of economic efficiency and welfare maximization, the aggregate effect of demand response is a wash producing no economic net benefit. Dr. Hogan asserts that Commission policy citing the benefits of price reduction in support of demand response compensation would amount to no less than an application of regulatory authority to enforce a buyers' cartel. He states that the Commission has been vigilant and aggressive in preventing buyers and sellers from engaging in market manipulation to influence prices, and it would be fundamentally inconsistent for the Commission to design demand response compensation policies that coordinate and enforce such price manipulation.

27. Dr. Hogan argues that the ideal and economically efficient solution regarding demand response compensation is to implement retail real-time pricing at the LMP, thereby eliminating the need for demand response programs. Realizing that this is unattainable at the present time, Dr. Hogan goes on to propose a next-best solution, which he believes is to pay demand

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[62] ISO-NE May 13, 2010 Comments at 3-4.

[63] *Id*. at 28.

response compensation in the amount of LMP-G, or some amount that simulates explicit contract demand response (such as "buy-the-baseline" approach discussed below). These options, he argues, more than paying LMP, better support notions of comparability between demand response resources and generation.[64]

28. The New York Commission, however, argues that requiring payment of LMP-G would result in an administrative burden of tracking retail rates for the multiple utilities, ESCOs and power authorities and create undue confusion for retail customers and administrative difficulties for state commissions and ISOs and RTOs.[65]

29. Consistent with Dr. Hogan's arguments, some commenters assert that demand response providers should actually own or pay for electricity prior to, what commenters characterize as, an effective reselling of the electricity back to the market in the form of demand response. For example, these commenters suggest that the demand response provider purchase the power in the day-ahead market and resell it in the real-time markets.[66] EPSA argues that there must be some purchase requirement or representative offset to allow a demand response provider to "sell" a commodity that it owns to the ISO or RTO.[67] EPSA argues that such a requirement would send an

[64] Hogan Affidavit, ISO RTO Council May 13, 2010 Comments at 5.

[65] New York Commission May 13, 2010 Comments at 8.

[66] *See*, *e.g*., ISO-NE IMM May 13, 2010 Comments at 4-5; Midwest ISO TOs May 13, 2010 Comments at 14; PJM May 13, 2010 Comments at 5; and Duke Energy May 13, 2010 Comments at 2.

[67] EPSA June 30, 2010 Comments at 3.

efficient price signal, reduce incentives for gaming the system, and help address difficulties with measurement and verification of a demand reduction. EPSA highlights an ISO-NE IMM recommendation that, if the Commission permits LMP payment, it should also adopt a "buy-the-baseline" approach requiring demand response resources to purchase an expected amount of energy consumption in the day-ahead energy market and subsequently sell any demand reduction from that level in the real-time market.[68]

30. Viridity, on the other hand, argues that forcing customers to buy and then resell electricity will lead to too little demand response and that adopting a "buy-the-baseline" approach would constitute an inappropriate exercise of Commission authority to effectively force parties into contracts. Viridity and DR Supporters state that any characterization of demand response as a purchase and then resale of energy is erroneous[69] and based on the flawed assumption that demand response resources are reselling energy. They state that the description of demand response as a reselling of energy has been correctly rejected by the Commission in *EnergyConnect*, where the Commission stated that it was establishing a policy of treating demand response as a service rather than a purchase and sale of electric energy.[70]

31. DR Supporters further argues that, despite claims to the contrary, paying full LMP to demand response providers does not constitute a subsidy for

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[68] EPSA June 30, 2010 Comments at 23.

[69] Viridity Energy June 18, 2010 Comments at 25.

[70] DR Supporters Aug. 30, 2010 Reply Comments at 10 (citing *EnergyConnect, Inc*., 130 FERC ¶ 61,031 at P 30-31 (2010)).

demand response any more than the remunerations of generators for the power that they sell. As Dr. Kahn states:

> Does this plan involve double compensation, as [Dr.] Hogan asserts, at the expense of power generators—of successful bidders promising to induce efficient demand curtailment and of consumers induced to practice it? Certainly not: the decrease in the revenue of the generators is (and consequent savings by consumers are) matched by the savings in their (marginal) costs of generating that power; the successful bidders for the opportunity to induce that consumer response are compensated for the costs of those efforts by the pool, whose (marginal) costs they save by assisting consumers to reduce their purchases.[71]

32. Viridity further disputes Dr. Hogan's argument that payment of LMP for demand response will distort an otherwise optimal market. Viridity posits that such arguments ignore dislocations in the wholesale power markets, the existence of market power that must be mitigated, imperfect information available to customers, barriers to entry and uneconomic resources dispatched to fulfill must-run requirements.[72] Viridity further states that Dr. Hogan's arguments fail to

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[71] DR Supporters Aug. 30, 2010 Reply Comments, Kahn Affidavit at 10.

[72] Viridity June 18, 2010 Comments at 13 ("Importantly, Dr. Hogan (and others) in opposing the proposed rulemaking fails to acknowledge the limits of the Commission's jurisdiction, and wide spread dislocations and distortions in virtually all economic aspects of relevant energy markets (including fuels, facilities, pricing, environmental attributes, information and participation)." (Affidavit of John C. Tysseling, Ph.D.)).

acknowledge the limits of the Commission's jurisdiction and widespread dislocations and distortions in virtually all economic aspects of relevant energy markets (including fuels, facilities, pricing, environmental attributes, information and participation) and fail to account for any market benefits of demand response.[73] Finally, Viridity argues that Dr. Hogan's arguments fail to reflect the many complex interactions between price, equipment operational requirements, and customer processes, which point to a complex demand response decision.[74]

33. In addition to physical and economic comparability, some commenters contrast the environmental effects of generation and demand response resources. EDF notes that current market prices fail to internalize environmental externalities—including toxic air pollution, greenhouse gas pollution, and land and water use impacts—and other social costs. EDF asserts that the social impact of these environmental externalities is especially acute at peak times, positing that generation sources used for marginal supply at such times ("peaker plants") are among the oldest, dirtiest, and most inefficient in the fleet.[75] The American Clean Skies Foundation contends that fossil-fuel generators are typically mispriced because wholesale prices radically understate the full environmental and health costs associated with such generators.[76] Indeed, some commenters, such as Alcoa, argue that because demand response does not result

[73] Viridity Reply Comments at 13.

[74] Viridity Reply Comments at 14.

[75] EDF Oct. 13, 2010 Comments at 2.

[76] American Clean Skies Foundation May 13, 2010 Comments at 4.

in the external costs associated with generation (e.g., greenhouse gas emissions), instead resulting in less greenhouse gas emissions than generation, it should be compensated at more than LMP.[77]

34. Taking the opposite view concerning environmental externalities, EPSA states that paying LMP for demand response will merely encourage load to switch to off-grid power (or behind-the-meter generation), while still being compensated, and that such behind-the-meter generation produces more greenhouse gases and other air emissions than electricity from the regional energy market.[78]

35. Some commenters discuss comparability of generation and demand response in terms of the market rules that apply to each resource, arguing that both resources should be comparably compensated only if the same rules for participation apply to both resources, and both resources are held to the same standards for dispatchability.[79] They also argue that similar penalty structures should apply to demand response resources as apply to generation, and that demand response participation must be subject to market monitoring.[80] Calpine adds that to the extent demand response resources are used and treated on par with generators for purposes of compensation, they should be subject to the same performance

[77] Alcoa May 13, 2010 Comments at 9.

[78] EPSA May 13, 2010 Comments at 60.

[79] ODEC May 13, 2010 Comments at 12; Westar May 13, 2010 Comments at 5-6.

[80] *Id*.

testing, penalties, and other similar requirements as generators.[81]

36. Some commenters address the comparability of demand response providers and generators in terms of maintaining system reliability. PIO argues that reductions in consumption provide additional reliability.[82] According to the NEMA, North American Electric Reliability Corporation (NERC) standards suggest that, from a reliability perspective, load reductions are equivalent or even superior to generator increases for balancing purposes. For example, while specific to the Western Interconnection, BAL-002-WECC-1 lists interruptible load as comparable to generation deployable within 10 minutes.[83] EPSA maintains that demand response resources are not full substitutes based on the nature of their participation and the rules applicable to each resource in the energy markets, pointing out, for example, that, unlike generators, demand response providers are not subject to regional and NERC mandatory reliability standards.[84]

37. On the other hand, PSEG argues that a MW of demand response does not make the same contribution towards system reliability as a MW of generation, because demand response committed as a capacity resource is only required to perform for a limited number of times over the peak period. PSEG refers to PJM's capacity market, for example, in which demand response only has to perform 10 times during the entire summer peak period, and then only for six hours

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[81] Calpine May 13, 2010 Comments at 5.

[82] PIO May 13, 2010 Comments at 8.

[83] NEMA May 13, 2010 Comments at 2.

[84] EPSA May 13, 2010 Comments at 7.

per response. In contrast, PSEG argues, generators are available for dispatch, 24 hours a day, 365 days per year, except for a small percentage of time for forced and planned outages. PSEG further asserts that additional reliability standards—applicable to generating facilities, but not to demand response—increase the relative reliability value of generating resources to the system.[85]

b) Appropriateness of a Net Benefits Test

38. Some commenters assert that demand response providers should be paid LMP only when the benefits of demand response compensation outweigh the energy market costs to consumers of paying demand response resources, i.e., when cost-effective, as determined by some type of net benefits or cost-effectiveness test.[86] They maintain that paying LMP for demand response in all hours, including off-peak hours, might not result in net benefits to customers, because the payments might be substantially more than the savings created by reducing the clearing price at that time.[87] According to these commenters, net benefits are most likely to be positive and greatest when the supply curve is steepest, which typically occurs in highest-cost, peak hours.[88] They argue that experience to date has shown positive benefits from

[85] PSEG May 13, 2010 Comments at 8.

[86] *See generally* May 13, 2010 Comments of NYSCPB; NECA; Capital Power; NECPUC; Maryland Commission; New York Commission; NSTAR; National Grid; NE Public Systems.

[87] Capital Power May 13, 2010 Comments at 5; P3 May 13, 2010 Comments at 5.

[88] NECPUC May 13, 2010 Comments at 13; *see also* Sept. 13, 2010 Tr. 13:6-19 (Mr. Keene); Maryland Commission May 13, 2010 Comments at 4-5.

demand response as a peak system resource, and that, during peak periods, the positive economics of demand response are generally very clear and a cost-benefit analysis may not be needed.[89] Furthermore, some commenters suggest that limiting the hours in which demand response resources are paid LMP could help establish better baselines for measuring whether a demand response provider has, in fact, responded.[90]

39. Some commenters who oppose paying LMP in all hours for demand response also suggest various approaches, including net benefits tests, for determining when LMP should apply. The stated purpose of any of these tests would be to determine the point at which the incremental payment for demand response equals the incremental benefit of the

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[89] *See*, *e.g*., ACEEE Oct. 13, 2010 Comments 3-4. *See also* National Grid May 13, 2010 Comments at 4-5; NSTAR Electric Company (NSTAR) May 14, 2010 Comments at 3; Maryland Commission May 13, 2010 Comments, submitting Analysis of Load Payments and Expenditures under Different Demand Response Compensation Schemes at 10-11 (discussing PJM analysis showing that paying demand response providers LMP for all hours after compensating LSEs for lost revenues would not benefit customers in general but that positive economic benefits results when demand response providers receive LMP during at least the top 100 hours (the highest priced energy hours)).

[90] *See*, *e.g*., CDWR May 13, 2010 Comments at 11; National Grid May 13, 2010 Comments at 8; ISO-NE May 13, 2010 Comments at 34; ACEEE Oct. 13, 2010 Comments 4. *But see* ISO-NE May 13, 2010 Comments at 32-33 (contending that no baseline estimation methodology that relies upon historical customer meter data can accurately and reliably estimate an individual customer's normal energy usage pattern if that customer responds frequently to price signals).

reduction in load; payment of LMP would apply only up to that point.[91]

40. Opposition to use of a net benefits test comes from several directions. Numerous commenters, primarily industrial consumers and some consumer advocates, argue that a net benefits test will reduce competition,[92] have a "chilling effect" on the development of demand response,[93] and be costly and complex to implement.[94] Some commenters further state that no net benefits test is needed because the merit-order bid stack and market clearing function in a wholesale market, by definition, assures that the benefits to the system of demand response exceed the costs, and that the resource that clears is the lowest cost resource; otherwise, demand response would not dispatch ahead of competing alternatives.[95]

41. Another set of commenters argues that a net benefits test is unnecessary and inappropriate for different reasons.[96] These commenters assert that a

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[91] NECAA May 13, 2010 Comments at 11; NYSCPB May 13, 2010 Comments at 5; National Grid May 13, 2010 Comments at 4-5.

[92] Viridity Oct. 13, 2010 Comments at 14.

[93] NAPP Oct. 13, 2010 Comments at 2.

[94] Viridity Oct. 13, 2010 Comments at 14; NAPP Oct. 13, 2010 Comments at 3; AMP Oct. 13, 2010 Comments at 4; CAISO Oct. 13, 2010 Comments at 5 and 16.

[95] EDF Oct. 13, 2010 Comments at 2; Viridity Oct. 13, 2010 Comments at 10; ELCON Oct. 13, 2010 Comments at 3.

[96] *See*, *e.g*., Oct. 13, 2010 Comments of: Midwest TDUs at 4-5; NEPGA at 8, NJBPU at 2-3; NAPP at 2-3; P3; SPP at 3-4; SDG&E, SoCal Edison, and PG&E at 4-6; Viridity Energy at 2; ELCON at 2; AMP at 2; CDWR at 1, 4-5; CAISO at 4, 15; Detroit Edison at 2; Smart Grid Coalition at 2; Duke Energy at 2; EDF

net benefits test would be very costly and difficult to implement, that RTOs and ISOs cannot implement a net benefits test,[97] and that such a test is unnecessary with the economically efficient compensation level for demand response resources.[98] According to Andy Ott of PJM, "[t]he implicit assumption in developing a benefits test for purposes of compensation would be that you could actually determine individual customers, whether they benefitted or not. That type of analysis would be very costly to implement." [99] Midwest ISO TOs further assert that it would be difficult to prescribe by regulation the hours in which demand response provides net benefits because system conditions and load patterns change across seasons and over time.[100] NEPGA argues that compensating demand response resources at LMP whenever a reduction in consumption suppresses energy prices enough to provide net benefits to load is neither just and reasonable, nor in the public interest.[101] NEPGA states that the Commission recognized in *Amaranth Advisors*[102] that, if prices are suppressed below competitive, market levels, society as a whole is worse off. According to NEPGA, the goal

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at 2; FTC at 1; EPSA at 4; Indicated New York TOs at 3; Midwest ISO at 9; Steel Manufacturers Ass'n at 3.

[97] P3 Oct. 13, 2010 Comments at 5.

[98] Sept. 13, 2010 Tr. 155:21-24 (Mr. Robinson); Sept. 13, 2010 Tr. 141-42 (Mr. Centolella); Dr. Hogan Sept. 13, 2010 Comments at 5; Sept. 13, 2010 Tr. 60 (Dr. Shanker); Sept. 13, 2010 Tr. 27 (Mr. Newton); SDG&E May 13, 2010 Comments at 4.

[99] Sept. 13, 2010 Tr. 19 (Mr. Ott).

[100] Midwest ISO TOs May 13, 2010 Comments at 16.

[101] NEPGA June 21, 2010 Comments at 1-2.

[102] 120 FERC ¶ 61,085 (2007).

is to get the *right* price—the economically efficient price produced by competitive markets.

42. NYISO posits that a rule mandating payment of LMP-G avoids the need to develop a net benefits test. NYISO further states, however, that if the Commission decides to move forward with LMP for demand response, it should craft a net benefits test that minimizes any opportunities for distorting market prices or exploiting market inefficiencies. Citing support for Dr. Hogan's arguments, NYISO states that "a net benefits test should ensure that the demand response program does not have negative net benefits compared to no program at all. The criterion to apply would focus on the bid-cost savings of generation and load, with the load bids adjusted for the effects of avoidance of the retail rate."[103]

c) Standardization or Regional Variations in Compensation

43. With regard to potential regional variations for compensation mechanisms across RTO and ISO markets, many commenters, mostly those in support of the NOPR's proposed compensation level, endorse standardization.[104] Some parties, primarily industrial

[103] NYISO Oct. 13, 2010 Comments at 3-4.

[104] *See* May 13, 2010 Comments of: ArcelorMittal; Alcoa; ACENY; ACC; AFPA; CDWR; Mayor Bloomberg; Consert; CDRI; CPower; DR Supporters; Derstine's; Durgin; Electricity Committee; ELCON; Electrodynamics; ECS; EnerNOC; ICUB; IECA; IECPA; Irving Forest; Joint Consumers; Limington; Madison Paper; Massachusetts AG; NEMA; National Energy; National League of Cities; NJBPU; NAPP; Occidental; Okemo; Partners; Pennsylvania Department of Environment; Pennsylvania Commission; Rep. Chris Ross; Precision; PRLC; Raritan ; SDEG, SoCal; PG&E; Schneider; Governor O'Malley;

customers and some customer advocates, argue that, regardless of location, both demand response providers and generators provide a comparable service in terms of balancing supply and demand, as discussed above, and therefore should be comparably compensated at the LMP.[105] They argue that fair, non-discriminatory markets must adapt and eliminate barriers to entry to the use and incorporation of traditional and non-traditional resources—where non-traditional resources include actively-managed demand—in the dispatch and management of the electric system.[106] They further posit that the lack of a unified policy itself represents a regulatory barrier to demand response,[107] and that a consistent set of rules reduces the costs and complexities of demand response participation and facilitates training and transfer of personnel across regions.[108] To that end, many commenters argue that adopting a unified approach to demand response compensation at the LMP, as opposed to allowing regional variation including payment of something less than LMP, is necessary to overcome the barriers to entry of demand response providers.[109] Reciting the many benefits of demand reductions in energy use, these commenters support a compensation level that will provide a catalyst for

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Steel Manufacturers Ass'n; Verso; Viridity; Virginia Committee; Wal-Mart; Waterville.

[105] *See*, *e.g.*, Steel Manufacturers Ass'n May 13, 2010 Comments at 12; NEMA May 13, 2010 Comments at 5.

[106] Steel Manufacturers Ass'n May 13, 2010 Comments at 12.

[107] PIO May 13, 2010 Comments at 9; DR Supporters Aug. 30, 2010 Comments at 6-7.

[108] *See*, *e.g.*, Alcoa May 13, 2010 Comments at 13.

[109] NECPUC May 13, 2010 Comments at 4; NYISO May 13, 2010 Comments at 16.

private sector engagement in improved energy management practices. Viridity argues that the near absence of demand response participating in energy markets is powerful empirical proof that current, varying levels of compensation are inadequate—especially in markets that start with a market-based level of compensation and then reduce it by the generation portion of a customer's retail rate (LMP-G).[110]

44. Other commenters caution against standardizing the compensation level for demand response, pointing to regional differences in market structure, state regulatory environment, and resource mix.[111]

3. Commission Determination

45. The Commission acknowledges the diverging opinions of commenters regarding the appropriate level of compensation for demand response resources. As discussed above, commenters are split on this issue, with some in favor of paying the LMP for demand reductions in the day-ahead and real-time energy markets in all hours, others arguing that paying the LMP for demand reductions under any conditions will result in over-compensation or distortions in incentives to reduce consumption, and still others arguing that paying the LMP for demand reductions is only appropriate when it is reasonably certain to be cost-effective.

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[110] Viridity Energy May 13, 2010 Comments at 4.

[111] *See*, *e.g.*, May 13, 2010 Comments of: ConEd at 3-4; Consumers Energy at 2; California Commission at 9; CMEEC at 2-3, 14-15; Detroit Edison at 3-5; Dominion at 8; Duke Energy at 4; EPSA at 6; Hess at 4; Indicated New York TOs at 3; Maryland Commission at 5; Midwest TDUs at 2, 6; Midwest ISO TOs at 16; National Grid at 5-6; 11-12; New York Commission at 4, 11; NCPA at 3; NYISO at 2-3; ODEC at 27; PJM at 5-6; SPP at 1.

46. In the face of these diverging opinions, the Commission observes that, as the courts have recognized, "'issues of rate design are fairly technical and, insofar as they are not technical, involve policy judgments that lie at the core of the regulatory mission.'"[112] We also observe that, in making such judgments, the Commission is not limited to textbook economic analysis of the markets subject to our jurisdiction, but also may account for the practical realities of how those markets operate.[113]

47. As discussed further below, the Commission agrees with commenters who support payment of LMP under conditions when it is cost-effective to do so, as determined by the net benefits test described herein.[114] We have previously accepted a variety of ISO and RTO proposals for compensation for demand response

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[112] *Elec. Consumers Res. Council v. FERC*, 407 F.3d 1232, 1236 (D.C. Cir. 2005) (quoting *Pub. Util. Comm'n of the State of Cal. v. FERC*, 254 F.3d 250, 254 (D.C. Cir. 2001)); *see also Town of Norwood v. FERC*, 962 F.2d 20, 22 (D.C. Cir. 1992).

[113] *See Elizabethtown Gas Co. v. FERC*, 10 F.3d 866, 872 (D.C. Cir. 1993) ("It is the FERC's established policy to consider equitable factors in designing rates, and to allow for phasing in of changes where appropriate . . . . It is hardly arbitrary or capricious so to temper the dictates of theory by reference to their consequences in practice."); *Vermont Dep't of Pub. Serv. v. FERC*, 817 F.2d 127, 135 (D.C. Cir. 1987) ("Indeed, 'the congressional grant of authority to the agency indicates that the agency's interpretation typically *will* be enhanced by technical knowledge.'" (quoting *Nat'l Fuel Gas Supply Corp. v. FERC*, 811 F.2d 1563, 1570 (D.C. Cir. 1987))); *Columbia Gas Transmission Corp. v. FERC*, 750 F.2d 105, 112 (D.C. Cir. 1984) ("the Commission is vested with wide discretion to balance competing equities against the backdrop of the public interest").

[114] *See generally* May 13, 2010 Comments of NYSCPB; NECA; Capital Power; NECPUC; Maryland Commission; New York Commission; NSTAR; National Grid; NE Public Systems.

resources participating in organized wholesale energy markets. We find, based on the record here that, when a demand response resource has the capability to balance supply and demand as an alternative to a generation resource, and when dispatching and paying LMP to that demand response resource is shown to be cost-effective as determined by the net benefits test described herein, payment by an RTO or ISO of compensation other than the LMP is unjust and unreasonable. When these conditions are met, we find that payment of LMP to these resources will result in just and reasonable rates for ratepayers.[115] As stated in the NOPR, we believe paying demand response resources the LMP will compensate those resources in a manner that reflects the marginal value of the resource to each RTO and ISO.[116]

48. The Commission emphasizes that these findings reflect a recognition that it is appropriate to require compensation at the LMP for the service provided by demand response resources participating in the organized wholesale energy markets only when two conditions are met:

- The first condition is that the demand response resource has the capability to provide the service, i.e., the demand response resource must be able to displace a generation resource in a manner that serves the RTO or ISO in balancing supply and demand.

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[115] The Commission's findings in this Final Rule do not preclude the Commission from determining that other approaches to compensation would be acceptable when these conditions are not met.

[116] NOPR at P 12.

- The second condition is that the payment of LMP for the provision of the service by the demand response resource must be cost-effective, as determined by the net benefits test described herein.

49. With respect to the first, capability-related condition, we note that a power system must be operated so that there is real-time balance of generation and load, supply and demand. An RTO or ISO dispatches just the amount of generation needed to match expected load at any given moment in time. The system can also be balanced through the reduction of demand.[117] Both can have the same effect of balancing supply and demand at the margin either by increasing supply or by decreasing demand.

50. With respect to the second cost-effectiveness condition, the record leads us to alter the proposal set forth in the NOPR in this proceeding. As various commenters explain, dispatching demand response resources may result in an increased cost per unit to load associated with the decreased amount of load paying the bill, depending on the change in LMP relative to the size of the energy market. As stated above, this is the billing unit effect of

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[117] Andrew L. Ott Sept. 13, 2010 Statement at 1. Economic and Capacity-based demand response clearly provides benefits to regional grid operation and the wholesale market operation . . . . These demand resources provide benefits by providing valuable alternatives to PJM in maintaining operational reliability and in promoting efficient market operations. *Id*. at 1; *see also* CDRI May 13, 2010 Comments at 10; CDWR May 13, 2010 Comments at 5; NJPBU May 13, 2010 Comments at 2.

dispatching demand response resources.[118] However, when reductions in LMP from implementing demand response results in a reduction in the total amount consumers pay for resources that is greater than the money spent acquiring those demand response resources at LMP, such a payment is a cost-effective purchase from the customers' standpoint.[119] In comparison, when wholesale energy market customers pay a reduced price attributable to demand response that does not reduce total costs to customers more than the costs of paying LMP to the demand response dispatched, customers suffer a net loss. Implementation of the net benefits test described herein will allow each RTO or ISO to distinguish between these situations.

51. This billing unit effect and the net benefits test through which it is addressed herein, warrant more detailed discussion. In the organized wholesale energy markets, the economic dispatch organizes offers from lowest to highest bid in order to balance supply and demand, taking into account other parameters such as requirements for a generator to operate at a minimum level of output or minimum amount of time, reserve

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[118] As stated above, dispatching generation resources does not produce this billing unit effect because it does not result in a decrease of load.

[119] As a simple example, assume a market of 100 MW, with a current LMP of \$50/MWh without demand response, and an LMP of \$40/MWh if 5 MW of demand response were dispatched. Total payments to generators and load would be \$4,000 with demand response compared to the previous \$5,000. Even though, the reduced LMP is now being paid by less load, only 95 MW compared to 100 MW, the price paid by each remaining customer would decrease from \$50/MWh to \$42.11/MWh (\$4,000/95). Therefore, the payment of LMP to demand resources is cost-effective.

requirements and so forth. With dispatch of a demand response resource, the load also goes down, that is, the level of remaining load falls. However, the "supply" of resources deployed—which includes both generation and demand response—does not fall. The total costs to the system for these resources must then be allocated among the reduced quantity of remaining load.

52. In the absence of the net benefits test described herein, the RTO's or ISO's economic dispatch ordinarily would select demand response when it is the incremental resource with the lowest bid. However, if the next unit of generation is not sufficiently more expensive than the demand response resource, the decrease in LMP multiplied by the remaining load would not be greater than the costs of dispatching the demand response resource. In this situation, dispatching the demand response resource would result in a higher price to remaining customers than the dispatch of the next unit of generation in the bid stack. While the demand response resource appears cost competitive in the dispatch order, selection of the demand response resource increases the total cost per unit to remaining load, and it would not be cost-effective to dispatch the demand response resource.

53. For this reason, the billing unit effect associated with dispatch of a demand response resource in an energy market must be taken into account in the economic comparison of the energy bids of generation resources and demand response resources.

Therefore, rather than requiring compensation at LMP in all hours, the Commission requires the use of the net benefits test described herein to ensure that the overall benefit of the reduced LMP that results from dispatching demand response resources exceeds the cost of dispatching those resources. When the above-noted conditions of capability and of cost-effectiveness are met, it follows that demand response resources that clear in the day-ahead and real-time energy markets should receive the LMP for services provided, as do generation resources. LMP represents the marginal value of an increase in supply or a reduction in consumption at each node within an ISO or RTO, i.e., LMP reflects the marginal value of the last unit of resources necessary to balance supply and demand. Indeed, LMP has been the primary mechanism for compensating generation resources clearing in the organized wholesale energy markets since their formation.[120]

54. The Commission finds that demand response resources that clear in the day-ahead and real-time energy markets should receive the same market-clearing LMP as compensation in the organized wholesale energy markets when those resources meet the conditions established here as a cost-effective alternative to the next highest-bid generation resources for purposes of balancing the energy market. We discuss below the comments filed on these issues.

55. Some commenters dispute that the foregone consumption of energy by demand response resources performs the service of balancing supply and demand in the energy market as would energy supplied by generators in the day-ahead and real-time energy markets, arguing that it is inappropriate to pay

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[120] *See* DR Supporters Aug. 30, 2010 Reply Comments (Kahn Affidavit at 2 (footnote omitted)).

electric consumers to not consume.[121] The Commission disagrees. Generation and load must be balanced by the RTOs and ISOs when clearing the day-ahead and real-time energy markets, and such balancing can be accomplished by changes in either supply or demand. The Commission finds that in the organized wholesale energy markets demand response can balance supply and demand as can generation.

56. Commenters that oppose this finding do not adequately recognize a distinctive and perhaps unique characteristic of the electric industry. The electric industry requires instantaneous balancing of supply and demand at all times to maintain reliability. It is in this context that the Commission finds that demand response can balance supply and demand as can generation when dispatched, in the organized wholesale energy markets.

57. Due to a variety of factors, demand responsiveness to price changes is relatively inelastic in the electric industry and does not play as significant a role in setting the wholesale energy market price as in other industries. The Commission has recognized that barriers remain to demand response participation in organized wholesale energy markets. For example, in Order No. 719, the Commission stated:

> [D]espite previous Commission and RTO and ISO efforts to facilitate demand response, regulatory and technological barriers to demand response participation persist, thereby limiting the benefits that would otherwise result. A market functions effectively only when both supply and demand can

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[121] *See*, *e.g*., ISO-NE May 13, 2010 Comments at 3; APPA May 13, 2010 Comments at 12; Capital Power May 13, 2010 Comments at 2; EPSA May 13, 2010 Comments at 72.

> meaningfully participate, and barriers to demand response limit the meaningful participation of demand in electricity markets.[122]

Barriers to demand response participation at the wholesale level identified by commenters include the lack of a direct connection between wholesale and retail prices,[123] lack of dynamic retail prices (retail prices that vary with changes in marginal wholesale costs), the lack of real-time information sharing, and the lack of market incentives to invest in enabling technologies that would allow electric customers and aggregators of retail customers to see and respond to changes in marginal costs of providing electric service as those costs change. For example, Dr. Kahn states:

> These circumstances—specifically, the fact that pass-through of the LMP is costly and (perhaps) politically infeasible, the possibly prohibitive cost of the metering necessary to charge each ultimate user, moment-by-moment, the often dramatic changes in true marginal costs for each—can justify direct payment at full LMP to distributors and ultimate customers who promise to guarantee

[122] Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 83 (citing Federal Energy Regulatory Commission Staff, A National Assessment of Demand Response Potential (June 2009), found at http://www.ferc.gov/legal/staff-refports/06-09-demand-response.pdf; Barriers to Demand Side Response in PJM (2009)). In compliance filings submitted by RTOs and ISOs and their market monitors pursuant to Order No. 719, as well as in responsive pleadings, parties have mentioned additional barriers, such as the inability of demand response resources to set LMP, minimum size requirements, and others.

[123] *See*, *e.g.*, Monitoring Analytics May 13, 2010 Comments at 4-6.

> their immediate response to such increases in true marginal costs of supplying them.[124]

Furthermore, EnerNOC states:

> On a more fundamental level, the inadequate compensation mechanisms in place today in wholesale energy markets fail to induce sufficient investment in demand response resource infrastructure and expertise that could lead to adequate levels of demand response procurement. Without sufficient investment in the development of demand response, demand response resources simply cannot be procured because they do not yet exist *as resources*. Such investment will not occur so long as compensation undervalues demand response resources.[125]

58. The Commission concludes that paying LMP can address the identified barriers to potential demand response providers.

59. Removing barriers to demand response will lead to increased levels of investment in and thereby participation of demand response resources (and help limit potential generator market power), moving prices closer to the levels that would result if all demand could respond to the marginal cost of energy. To that end, the Commission emphasizes that removing barriers to demand response participation is

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[124] DR Supporters Sept. 16, 2009 Comments filed in Docket No. EL-09-68-000 (Kahn Affidavit at 6). *See also id*. at 4 (Customers offering to reduce consumption should be induced "to behave as they would if market mechanisms alone were capable of rewarding them directly for efficient economizing.").

[125] EnerNOC May 13, 2010 Comments at 4; *see also* Alcoa May 13, 2010 Comments at 4; Viridity May 13, 2010 Comments at 5-6.

not the same as giving preferential treatment to demand response providers; rather, it facilitates greater competition, with the markets themselves determining the appropriate mix of resources, which may include both generation and demand response, needed by the RTO and ISO to balance supply and demand based on relative bids in the energy markets. In other words, while the level of compensation provided to each resource affects its willingness and ability to participate in the energy market, ultimately the markets themselves will determine the level of generation and demand response resources needed for purposes of balancing the electricity grid.[126]

60. Another issue raised by a number of commenters, largely representing generators, is whether a lower payment based on LMP-G is the economically-efficient price that sends the proper price signal to a potential demand response provider. These commenters argue that, by not consuming energy, demand response providers already effectively receive "G," the retail rate that they do not need to pay. They therefore contend that demand response providers will be overcompensated unless "G" is deducted from payments made by the RTO or ISO for service in the wholesale energy market, resulting in a payment of LMP-G. These commenters suggest that payment of LMP-G will result in a price signal to demand response providers equivalent to the LMP (i.e., (LMP-G) + G). Similarly, some commenters argue that paying demand response resources the LMP will lead

[126] Generation and demand response resources have the potential to earn other revenues through bilateral arrangements, capacity markets where they exist, and ancillary services.

to a wholesale electricity price that is not economically efficient.[127]

61. The Commission disagrees with commenters who contend that demand response resources should be paid LMP-G in all hours. First, as discussed above, demand response resources participating in the organized wholesale energy markets can be cost-effective, as determined by the net benefits test described herein, for balancing supply and demand and, in those circumstances, it follows that the demand response resource should also receive compensation at LMP. Second, such comments largely rely on arguments about economic efficiency, analogizing to incentives for individual generators to bid their marginal cost. These arguments fail to acknowledge the market imperfections caused by the existing barriers to demand response, also discussed above. In Order No. 719, the Commission found that allowing demand response to bid into organized wholesale energy markets "expands the amount of resources available to the market, increases competition, helps reduce prices to consumers and enhances reliability." [128] Furthermore, Dr. Kahn argues that paying demand response LMP sets "up an arrangement that treats proffered reductions in demand on a competitive par with positive supplies; but the one is no more a [case of overcompensation] than the other: the one delivers electric power to users at marginal costs—the other—*reductions in cost*—both at competitively-determined levels."[129]

[127] *See* NEPGA June 21, 2010 Comments at 1-2.

[128] Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 154.

[129] DR Supporters Aug. 30, 2010 Reply Comments (Kahn Affidavit at 9-10).

62. Several other considerations also support this Commission conclusion. In the absence of market power concerns, the Commission does not inquire into the costs or benefits of production for the individual resources participating as supply resources in the organized wholesale electricity markets and will not here, as requested by some commenters, single out demand response resources for adjustments to compensation. The Commission has long held that payment of LMP to supply resources clearing in the day-ahead and real-time energy markets encourages "more efficient supply and demand decisions in both the short run and long run,"[130] notwithstanding the particular costs of production of individual resources. Commenters have not justified why it would be appropriate for the Commission to continue to apply this approach to generation resources yet depart from this approach for demand response resources.

63. In addition, we agree with the New York Commission that given the differences in retail rate structures across RTO footprints and even within individual states, requiring ISOs and RTOs to incorporate such disparate retail rates into wholesale payments to wholesale demand response providers would, even though perhaps feasible, create practical difficulties for a number of parties, including state commissions and ISOs and RTOs. Moreover, incorporating such rates could result in customer uncertainty as to the prevailing wholesale rate.

64. Some arguments advocating paying LMP-G rather than LMP are based on an assumption that demand response resources need to purchase the

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[130] *See New England Power Pool*, 101 FERC ¶ 61,344, at P 35 (2002).

energy in day-ahead markets or by other means and then "resell" the energy to the market in the form of demand response. However, as the Commission previously stated in *EnergyConnect*, the Commission does not view demand response as a resale of energy back into the energy market.[131] Instead, as the Commission also explained in *EnergyConnect* and in Order No. 719-A, the Commission asserts jurisdiction with respect to demand response in organized wholesale energy markets because of the effect of demand response and related RTO and ISO market rules on Commission-jurisdictional rates.[132]

65. With regard to the "buyers' cartel" argument, the Commission disagrees that market rules establishing circumstances in which particular resources can participate and receive the LMP represents cooperative price setting. RTOs and ISOs evaluate the bids from generation and demand response resources to establish the order of dispatch which secures the most economical supplies needed, consistent with the reliability constraints imposed on the system. Imposing a cost-effectiveness condition does not convert this unit commitment process by the RTO or ISO into collusion among bidders, whether generation or demand response. Furthermore, the market rules administering such a program would be approved by this Commission and demand response resources would be subject to Commission-approved rules, just like any other participants in the organized wholesale energy markets. In addition, arguments that the subject of this proceeding is equivalent to the types of

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[131] *See EnergyConnect*, 130 FERC ¶ 61,031 at P 32.

[132] *Id.*; *see also* Order No. 719-A, FERC Stats. & Regs. ¶ 31,292, at P 47.

market manipulation investigated in *Amaranth* and *ETP* are groundless and without merit. In *Amaranth*, the trader was accused of engaging in a fraudulent scheme with scienter in connection with a jurisdictional transaction. Here, there is no such allegation, merely speculation that the Commission is somehow facilitating coordination of demand-side bidders in order to lower prices.

66. Some commenters argue that demand response providers and generators should both be compensated at the market clearing price only if both are subject to the same market participation rules, penalty structures, testing requirements, and market monitoring provisions. The ISOs and RTOs already consider how to ensure comparability between demand response and generation in terms of market rules. [133] The Commission agrees that as a general matter demand response providers and generators should be subject to comparable rules that reflect the characteristics of the resource, and expect ISOs and RTOs to continue their evaluation of their existing rules in light of this Final Rule and make appropriate filings with the Commission.

67. Some commenters argue that the Commission should not impose a single pricing rule due to differences in market structure, state regulatory environment, and resource mix among the ISOs and RTOs. While such differences may exist, the commenters have not shown why such differences warrant a different compensation level among the ISOs and RTOs. As discussed above, regardless of the resource mix or the state regulatory environment, demand response, which satisfies the net benefits test

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[133] *See PJM Interconnection, L.L.C.*, 129 FERC ¶ 61,081 (2009).

described herein and can balance the system, is a cost-effective alternative to generation in the organized wholesale energy markets, and payment of LMP represents the marginal value of a decrease in demand.

B. Implementation of a Net Benefits Test

1. Comments

68. In response to questions that the Commission posed in the Supplemental NOPR, some commenters advocate a net benefits trigger based on a particular price threshold.[134] The NYISO currently has a static bid threshold of $75/MWh in its day-ahead demand response program.[135]

69. However, other commenters assert that using a static threshold based on historical data misses the changes that occur within electricity markets across seasons and years, and that it is erroneous to assume that all demand response occurring above a certain

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[134] For example, National Grid states that the threshold could be triggered by a particular price on the supply offer curve at which the additional cost of paying LMP to demand response resources is most likely to be outweighed by LMP reductions in the wholesale energy market as a result of the demand reductions produced by these resources. National Grid May 13, 2010 Comments at 6. Those in favor of a price threshold include National Grid (but allow the ISO or RTO to identify threshold based on analysis); NE Public Systems; NECPUC; ISO-NE (minimum offer price based on fixed heat rate, times a fuel price index); New York Commission (supports ISO-NE's heat rate indexed price threshold).

[135] NYISO implements a day-ahead demand response program by which resources bid into the market at a minimum of $75/MWh and can get paid the LMP. *See* section 4.2.2.9 ("Day-Ahead Bids from Demand Reduction Providers to Supply Energy from Demand Reductions") of NYISO's Market Services Tariff.

threshold price (for instance, at the very highest loads or highest priced hours) will result in lower costs to wholesale customers and that demand response is not cost-effective at prices below the static threshold price.[136] They argue that a static threshold offer price cannot easily adjust with changing energy market prices which may result in inefficient dispatch of demand resources, excluding demand response participation in hours when demand response can provide beneficial savings and including demand response participation in hours when there are no beneficial savings.[137] The New York Commission supports a dynamic, rather than a static bid threshold, arguing that, while a static bid threshold helps prevent demand response providers from gaming the system by seeking compensation for reducing electricity consumption for reasons other than market prices, it can also limit participation in a demand response program because prices might not exceed the threshold on a consistent basis.[138]

70. In a similar vein, some commenters suggest utilizing a dynamic bid threshold for determining when LMP payment would apply.[139] For example,

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[136] Sept. 13, 2010 Tr. 52-53 (Mr. Peterson); Massachusetts AG Oct. 13, 2010 Comments at 23.

[137] Massachusetts AG Oct. 13, 2010 Comments (attachment, Demand Response Potential in ISO New England's Day-Ahead Energy Market, Synapse Energy Economics, Inc. Oct. 11, 2010 at 9). *See generally*, NECPUC May 13, 2010 Comments at 18.

[138] *Id*.

[139] National Grid May 13, 2010 Comments at 6; New York Commission May 13, 2010 Comments at 10; Viridity May 13, 2010 Comments at 24. *See generally* NECPUC, New York Commission; ISO-NE; NSTAR; ACEEE; and NYSCPB Oct. 13, 2010 Comments.

NECPUC favors use of a dynamic mechanism such as a price threshold based on a preset heat rate of marginal generation and fuel price, like that currently used in New England's Day-Ahead Load Response Program (DALRP),[140] for the ISO-NE control area.[141] National Grid suggests a trigger, determined by each ISO or RTO, using a particular price on the supply offer curve at which the additional cost of paying LMP to demand resources is most likely to be outweighed by LMP reductions in the wholesale energy market as a result of the demand reductions.[142]

71. Still other commenters urge compensating demand response during an ISO- or RTO-defined period of critical high-cost hours in which it is cost-effective to pay LMP. These commenters argue that the effect of demand response on the market clearing price is greatest during a limited number of hours during the year.[143] Therefore, identifying the hours in which to pay LMP to demand response resources could be used as a cost-effective net benefits test with potential savings for ratepayers. According to PJM, further analysis is needed to ascertain the critical

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[140] The DALRP establishes a minimum offer price by approximating the variable cost component, in the form of a fuel cost, of a hypothetical peaking unit sufficiently high enough in the supply stack to ensure net benefits. On a monthly basis, this minimum offer price is reset to reflect the product of an appropriate fuel price index and a proxy heat rate. *See* NECPUC Oct. 13, 2010 Comments at 15.

[141] NECPUC Oct. 13, 2010 Comments at 14-16; NECPUC May 13, 2010 Comments at 17.

[142] *Id*. at 5-6.

[143] Maryland Commission May 13, 2010 Comments at 4-5; *see generally* NSTAR, ACEEE and NYSCPB Oct. 13, 2010 Comments.

high-cost hours in which it will be cost-effective to pay full LMP for demand response.[144]

72. The Consumer Demand Response Initiative (CDRI) proposes a mechanism for determining what demand response resources are cost-effective in any hour.[145] This dispatch algorithm tests whether the money necessary to compensate demand response is less than the cost savings due to the decreased market-clearing price resulting from implementing demand response. In a sense, it is a dynamic cost/benefit analysis built into the dispatch algorithm. This cost/benefit analysis accounts for the billing unit effect. The billing unit effect occurs when demand response resources are dispatched to balance the system; the associated reduction in load results in fewer MWh of realized load (demand) paying for the sum of generator and demand response resource MWh, so load pays an effective rate which is greater than the LMP set to procure resources. Some commenters assert that if the Commission finds that a net benefits test is needed, it should require organized wholesale energy market operators to implement a proposal similar to that submitted by CDRI.[146]

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[144] Maryland Commission May 13, 2010 Comments at 4 n.9.

[145] The approach submitted by CDRI was developed for implementation in the ISO-NE day-ahead energy market. The discussion here is generalized to be applicable to any energy market that uses security-constrained economic dispatch to select the least-cost resources and establish a market-clearing price.

[146] PIO July 27, 2010 Comments at 6; Massachusetts AG Oct. 13, 2010 Comments at 11; Viridity Oct. 13, 2010 Comments at 2. *See* CDRI May 13, 2010 Comments for a full description of the algorithms.

73. Under the proposal submitted by CDRI, the demand response bids are part of the supply stack to which a security-constrained economic dispatch process is applied. All demand response bids that result in a lower price to customers, including consideration of the reduced number of billing units, are selected while those bids that raise the price, as compared to selecting the next generation bid in the supply stack, are not. This dispatch algorithm, as proposed, would be used by the ISO or RTO to determine a revised LMP that would be charged to load. The revised LMP creates a surplus (or over-collection) of revenue for the ISO or RTO that is then distributed to the LSEs through a settlement algorithm with the goal of holding LSEs harmless.[147]

74. During the September 2010 Technical Conference, Dr. Ethier of ISO-NE stated that a dynamic net benefits test done on an hourly basis that examines the effect of the demand response resource on LMPs, similar to that proposed by CDRI, would become very complicated to implement and require essentially an iterative process.[148] Dr. Ethier states that the ISO would have to run the dispatch model to formulate a base LMP with no demand response and then re-run it with demand response in the market; however those two iterations alone do not "cover the whole waterfront" in terms of the possible iterations required. According to Dr. Ethier, the ISO could dispatch too much demand response the first time, or

[147] CDRI May 13, 2010 Comments Attachment B at 18. CDRI states that the dispatch and settlement algorithms "could be employed to evaluate dispatch and assure customer benefits, without being employed to perform allocations and settlements." CDRI Oct. 13, 2010 Comments at 4.

[148] Sept. 13, 2010 Tr. 80-81 (Dr. Ethier).

if the ISO first rejected dispatching demand response, it may need to go back and dispatch smaller amounts of demand response to determine what would happen to the LMPs. Dr. Ethier stated that it is unclear where the ISO would stop the iteration of testing the impact on LMPs of dispatching demand response.[149] Andy Ott of PJM also stated during the technical conference that implementing a net benefits test would entail an iterative process that would be costly and difficult, if the RTO could even do it.[150]

75. Other commenters do not support the use of a net benefits test, but state that if one is adopted it should be based on general principles that RTOs and ISOs must apply to their systems in determining when LMP payments will apply.[151] A few commenters articulated specific criteria to be used in a net benefits test.[152] AEP believes that the objective of an incentive payment for demand response resources on the basis of broad market benefits can be achieved through a review of the costs and benefits of individual providers. Constellation states that any net benefits

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[149] *Id.*

[150] Sept. 13, 2010 Tr. 82:16-21 (Mr. Ott).

[151] *See generally* AEP, Midwest ISO, Occidental, NYISO, Constellation Oct. 13, 2010 Comments.

[152] *See*, *e.g.*, Midwest ISO October 13, 2010 Comments at 9-14 and Table 1 (setting forth comprehensive list of benefits and costs of demand response by type of market participants); Occidental October 13, 2010 Comments at 4-5 (any net benefits test must take into consideration offsetting variables, such as higher LMPs in the subsequent periods where demand rebound increases market price, and capacity market price effects); AEP October 13, 2010 Comments at 3-4 (AEP does not recommend the use of a societal benefits component (i.e., health, environment, or employment efforts)).

test should be based on the difference between the value consumers receive from energy and the cost of energy production.[153]

76. ISO-NE argues that a net benefits test should be based on economic efficiency, the sum of producer and consumer surplus, which suggests that demand response incentives ought to be provided to encourage demand reductions when the cost of energy production exceeds the value of consumption, and to encourage usage when the cost of energy production is less than the value of consumption. ISO-NE further states that a net benefits test that focuses solely on consumer savings ignores the value lost by consumers when energy consumption levels are reduced in response to incentive payments. ISO-NE posits that any variant of a LMP payment should be limited to a very small number of high-priced hours to minimize the economic distortions and avoid significant administrative complexities.[154]

77. A few commenters state that policies affecting energy prices will also impact capacity prices because generation owners with fixed costs must raise capacity price offers to remain financially viable at lower energy prices.[155] ISO-NE and Pepco argue, therefore, that the Commission should adopt a net benefits test that considers the impact of demand response compensation on both energy and capacity markets.[156]

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[153] Constellation October 13, 2010 Comments at 3-4.

[154] ISO-NE Oct. 13, 2010 Comments at 4-5 and 21.

[155] *See, e.g.*, Sept. 13, 2010 Tr. 94:13-22 (Dr. Shanker); Sept. 13, 2010 Tr. 98:4-24 (Mr. Peterson); Sept. 13, 2010 Tr. 99:2-7 (Mr. Sunderhauf); ISO-NE Oct. 13, 2010 Comments at 5.

[156] Sept. 13, 2010 Tr. 99:1-24 (Mr. Sunderhauf); ISO-NE Oct. 13, 2010 Comments at 5.

According to ISO-NE, when considering capacity market impacts under full-LMP compensation, long-term increases in capacity prices in response to suppressed LMPs offset consumer savings and leaves consumers worse off over time.[157] Robert Weishaar of the DR Supporters argues that properly compensating demand response should flatten the load profile and decrease the forecast of load projections, which would reduce capacity clearing prices.[158] Donald Sipe of CDRI adds that to the extent that scarcity revenues are not sufficient, capacity markets are designed to ensure that a generator's capital costs are recovered; in a forward market that looks ahead as load adjusts, one can see whether a resource is performing or not. For purposes of long-run reliability, he argues, as long as compensation is in the amount that is necessary to induce new investment and reflects market value, the argument that demand response in the bid stack will push out generators is only true if generators are higher priced than the consumer resources that are brought by demand response.[159]

2. Commission Determination

78. For the reasons discussed previously, the Commission is requiring each RTO and ISO to implement the net benefits test described herein to determine whether a demand response resource is cost-effective. More specifically, the Commission is adopting two distinct requirements with respect to the net benefits test. While we find that the integration of

[157] ISO-NE Oct. 13, 2010 Comments at 6.

[158] Sept. 13, 2010 Tr. 103-104 (Mr. Weishaar).

[159] Sept. 13, 2010 Tr. 106:16-24 (Mr. Sipe).

the billing unit effect into the RTO/ISO dispatch processes has the potential to more precisely identify when demand response resources are cost-effective, we also recognize and understand the position of several of the RTOs and ISOs that modification of their dispatch algorithms may be difficult in the near term. Given these technical difficulties, we will require to RTOs and ISO to perform (1) the net benefits test described below to determine on a monthly basis under which conditions it is cost-effective to pay full LMP to demand resources;[160] and (2) a study of the feasibility of developing a mechanism for determining the cost-effective dispatch of demand resources.

79. First we direct each RTO and ISO to undertake an analysis on a monthly basis, based on historical data and the RTO's or ISO's previous year's supply curve, to identify a price threshold to estimate where customer net benefits, as defined herein, would occur. The RTO or ISO should determine the threshold price corresponding to the point along the supply stack for each month beyond which the benefit to load from the reduced LMP resulting from dispatching demand response resources exceeds the increased cost to load associated with the billing unit effect, and update the calculation monthly. The ISOs and RTOs are to determine monthly threshold prices based on

[160] There will be inherent differences in the supply curves determined by each RTO and ISO under the net benefits test required herein due to decisions the RTOs and ISOs must make based on supply data for their regions, the mathematical methods each RTO and ISO chooses to use for smoothing the supply curves, the certainty of changes in supply due to outages in each region, local generation heat rates, and the choice of relevant fuel price indices.

historical data. The threshold prices would be updated monthly as new data becomes available and posted on the RTO web site. For example, the RTO should conduct an analysis of supply curves for January through December 2010 to be used as a starting point to establish threshold prices for 2011. Those numbers would be updated monthly during 2011 for significant changes in resource availability and fuel prices, with the process repeated monthly to reflect that month's data from the previous year.[161] The supply curve analysis should be updated monthly, by the 15th day of the preceeding month in advance of the effective date, to allow demand response providers as well as other market participants to plan, while still reflecting current supply conditions.[162]

80. Based on historical evidence and analysis submitted in this proceeding, the threshold point along the supply stack for each month will fall in the area where the supply curve becomes inelastic, rather than the extreme steep portion at the peak or in the flat portion of the supply curve.[163] In other words, LMP

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[161] The ISOs and RTOs are to select a representative supply curve for the study month, smooth the supply curve using numerical methods, and find the price/quantity pair above which a one megawatt reduction in quantity that is paid LMP would result in a larger percentage decrease in price than the corresponding percentage decrease in quantity (billing units). Beyond that point, a reduction in quantity everywhere along an upward sloping supply curve would be cost-effective.

[162] Thus, the test is to determine where: (Delta LMP x MWh consumed) > (LMPNEW x DR); where LMPNEW is the market clearing price after demand response (DR) is dispatched and Delta LMP is the price before DR is dispatched minus the market clearing price after DR is dispatched.

[163] Supply elasticity is defined as the percentage change in quantity supplied divided by the percentage change in price.

will be paid to demand response resources during periods when the nature of the supply curve is such that small decreases in generation being called to serve load will result in price decreases sufficient to offset the billing unit effect. The Massachusetts AG noted that the actual supply stack has locally flat and steep sections at all bid prices. We recognize that the threshold price approach we adopt here may result in instances both when demand response is not paid the LMP but would be cost-effective and when demand response is paid the LMP but is not cost-effective. We accept this result given the apparent computational difficulty of adopting a dynamic approach that incorporates the billing unit effect in the dispatch algorithms at this time.[164]

81. We direct each RTO and ISO to file its analysis as supporting documentation to the accompanying tariff revisions with the Commission on or before July 22, 2011, along with proposed tariff revisions necessary to comply with this Final Rule. The filing should include the data, analytical methods and the actual supply curves used to determine the monthly threshold prices for the last 12 months to show how the RTO or ISO would calculate the curves.[165] The Commission-approved net benefits test methodology

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When the elasticity is less than or equal to one, supply is considered inelastic. So, for example, in the inelastic portion of the supply curve, a reduction in quantity supplied by one percent will result in more than a one percent decrease in price. Using the terms related to demand response compensation, the billing unit effect (percentage change in quantity supplied) will be more than offset by lower LMP (percentage change in price), thus resulting in lower prices for wholesale load.

[164] *See supra* note 114.

[165] *See supra* P 6.

must be posted on the RTO or ISO's website, with supporting documentation. The RTO or ISO must also post the price threshold levels that would have been in effect in the previous 12 months. In addition, when the net benefits test becomes effective, the supply curve analysis for the historic month that corresponds to the effective month should be updated for current fuel prices, unit availabilities, and any other significant changes to historic supply curve and posted on the RTO website (for example, the supply curve analysis for the March price threshold would be posted in mid-February). Finally, the supply curve analyses for all months should be updated and posted on the RTO website if a significant change to the composition or slope of the historic monthly curves occurs, such as extended outages or retirements not previously reflected.

82. Some commenters argue that that there would be no need for a net benefits test if demand response resources were paid LMP-G, while others argue that use of a net benefits test otherwise undermines our decision to compensate demand response resources at the LMP. As stated above, the Commission finds that when a demand response resource participating in an organized wholesale energy market is capable of balancing supply and demand in the energy market and is cost-effective, as determined by the net benefits test described herein, that demand response resource should receive the same compensation, the LMP, as a generation resource when dispatched. We see no reason to reduce that compensation simply to avoid the use of the net benefits test that will ensure benefits to load.

83. Nearly every participant in the net benefits panel at the September 13, 2010 Technical Conference

agreed that it would be counterproductive to defer to the RTO or ISO stakeholder process to determine when demand response provides net benefits without explicit guidance from the Commission.[166] We believe that this result, and the guidance provided in this Final Rule will provide for timely improvements to RTO and ISO market pricing for demand response resources participating in organized wholesale energy markets.

84. In addition to requiring each RTO and ISO to construct the net benefits test described herein, the Commission also imposes a second requirement for each RTO and ISO to undertake a study, examining the requirements for and impacts of implementing a dynamic approach to determine when paying demand response resources LMP results in net benefits to customers. We believe that integration of the billing unit effect into RTO and ISO dispatch algorithms holds promise for more accurately integrating demand resources on a dynamic basis into the dispatch of the RTOs and ISOs. In theory, this could help ensure that the cost-effective level of demand response resources is dispatched or scheduled into the organized wholesale energy markets. Given the potential of software enhancements to determine the amount of cost-effective demand response resources purchased in the day-ahead and real- time energy markets, we believe

[166] "[G]etting this decision resolved is an impediment to all the other stuff we want to do with price response to demand, and DR generally in our market. . . so until we get through this, we're not going to make much progress. . . the implication of that is if you send something back that leaves a lot of room for debate, it's going to be a while on all those other things." Testimony of Robert Ethier, Vice President, Market Design, ISO-NE, Sept. 13, 2010 Tr. at 136.

that it would be useful for the Commission to know more about the feasibility of and requirements for implementing improvements to the existing dispatch algorithms. Therefore, we will require each RTO and ISO to undertake a study, either individually or collectively, examining the requirements for, costs of, and impacts of implementing a dynamic net benefits approach to the dispatch of demand resources that takes into account the billing unit effect in the economic dispatch in both the day-ahead and real-time energy markets, and to file the results of their study with the Commission on or before September 21, 2012.

85. ISO-NE and Pepco suggest that the net benefits test also consider the impact of demand response compensation on both energy and capacity markets. However, this Final Rule is focused only on organized wholesale energy markets, not capacity markets.[167] Given the differences in capacity markets among the ISOs and RTOs, the record in this proceeding provides neither a reasonable basis for including capacity market effects in net benefits calculations in the energy markets, nor have ISO-NE and Pepco provided a methodology for taking such effects into account. Indeed, in some cases, the capacity markets already reflect energy and ancillary service revenue in determining capacity prices.

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[167] Additionally, the arguments presented for focusing on the effect of demand response compensation in wholesale energy markets on capacity markets were not convincing—that decreases in energy market revenues by generators will be recouped in the form of increased capacity prices. First, they fail to consider how the increased participation by demand resources could actually increase potential suppliers in the capacity markets by reducing barriers to demand resources, which would tend to drive capacity prices down. Second, they did not examine the way in which capacity markets already may take into account energy revenues.

C. Measurement and Verification

1. NOPR Proposal

86. In the NOPR, the Commission explained that demand response curtailment is a reduction in actual load as compared to the demand response provider's expected level of electricity consumption.[168] The NOPR did not address measurement and verification of demand response.

87. Each RTO and ISO with a demand response program has procedures for the measurement and verification of demand response. These procedures include techniques to establish a customer baseline for each demand response participant. This customer baseline then becomes the basis for measuring the quantity of demand response delivered to the wholesale market. Customer baselines are often based on historic load information, such as an average of five of the last ten comparable days' hourly load profile. Techniques vary among RTOs and ISOs and most have several techniques that may be allowed, depending on the demand response provider's characteristics.[169]

2. Comments

88. Commenters assert that the integrity of a demand response program is heavily dependent on

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[168] *Demand Response Compensation in Organized Wholesale Energy Markets*, FERC Stats. & Regs. ¶ 32,656, at P 1 (2010).

[169] *See*, *e.g*., ISO/RTO Council, North American Wholesale Electricity Demand Response 2010 Comparison, under the tab for "Performance Evaluation Methods" (http://www.isorto.org/atf/cf/#5b4e85c6-7eac-40a0-8dc3-003829518ebd'/IRCDR0M&V0STANDARDS0IMPLEMENTATION0COMPARISON(20100524).XLS).

measurement and verification.[170] Some commenters raise the issue that paying LMP in all hours presents a significant challenge to the accurate measurement and verification of demand response.[171] ISO-NE argues that when a market participant schedules demand reductions for many consecutive days, baselines may become stale—no longer reflecting a customer's "normal" electricity usage.[172] ISO-NE goes on to argue that "it is necessary to limit the number of hours or days that a demand resource could clear in the energy market so that the customer's 'normal' load can be estimated" to avoid the potential for manipulation.[173] In the context of the Commission's proposal to pay demand response the LMP in all hours, ISO-NE goes on to advocate requiring demand response to establish baselines by purchasing energy in the day-ahead market as a way to overcome its concerns with statistical baseline methods.[174] ISO-NE IMM makes

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[170] Illinois CUB May 14, 2010 Comments at 16-17; Joint Consumers May 13, 2010 Comments at 12; P3 May 12, 2010 Comments at 38; Westar May 13, 2010 Comments at 3.

[171] *See*, *e.g*., ISO-NE May 13, 2010 Comments at 32.

[172] *Id*.

[173] ISO-NE May 13, 2010 Comments at 34. ISO-NE identifies several practices that, in its view, might be deployed by a demand responder to receive payment when it has not, in fact, responded to price. ISO-NE states that observations of such behavior in the Fall of 2007 led it to limit the hours demand response offers could clear the market. Citing *ISO New England Inc*., Docket No. ER08-538-000 (February 5, 2008 filing). ISO-NE May 13, 2010 Comments at 32-34.

[174] *Id*.

similar arguments and recommendations.[175] Westar also appears to support this approach.[176]

89. Similarly, CPower notes that with some baseline methods, paying LMP in all hours could reward demand responders for any shift in demand from the baseline, not just shifting load from high LMP hours to low LMP hours, or could simply shift load from day-to-day in different hours to affect the calculation of actual curtailment, which it labels "checkerboarding." However, CPower believes that the capability of consumption management to shed or shift load for many hours is well into the future, and perhaps not a current concern. CPower also believes that baseline standards along with market monitoring will develop to meet these concerns.[177]

90. ISO-NE IMM asserts that "[if] the Commission adopts any proposal that permits the use of an administrative baseline it should explicitly state that any demand reductions offered into Commission-jurisdictional markets that are not genuine, even if they are the result of 'normal' activity . . . may be violations of the Commission's anti-manipulation rules and subject to penalties thereunder."[178]

91. Noting the ongoing efforts by the industry and the North American Energy Standards Board (NAESB) on measurement and verification, EnerNOC

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[175] ISO-NE IMM May 13, 2010 Comments at 9-13 and Attachment A.

[176] Westar May 13, 2010 Comments at 3.

[177] CPower May 13, 2010 Comments at 4-5.

[178] ISO-NE IMM May 13, 2010 Comments at 14 (footnotes omitted) (ISO-NE MMU also notes that "[i]n assessing whether demand reductions are genuine, allowance should be made for non-performance analogous to a generator's forced outage.").

takes the view that resolution of customer baseline issues should not delay the issuance of this Final Rule.[179]

92. Finally, some commenters assert that measurement and verification methods should not be standardized, but left to the RTOs and ISOs to reflect the unique features of their individual energy, ancillary services, and capacity markets.[180]

3. Commission Determination

93. The Commission agrees with commenters who assert that measurement and verification are critical to the integrity and success of demand response programs. Without a determination of a demand response provider's expected use of power, the ISOs and RTOs cannot determine whether that provider has in fact reduced its energy usage when paid to do so. Towards that end, all the RTOs and ISOs already have measurement and verification protocols for their demand response programs.[181] In addition, we have adopted Phase I standards for measurement and verification published by the North American Energy Standards Board,[182] and have recognized the potential benefits of the continuing NAESB effort to craft

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[179] EnerNOC, Inc. May 13, 2010 Comments at 4.

[180] ECS May 13, 2010 Comments at 3; Indicated New York TOs May 13, 2010 Comments at 2-3; Midwest ISO May 13, 2010 Comments at 17, 21; National Grid May 13, 2010 Comments at 11-12; NSTAR May 14, 2010 Comments at 9; PPL May 13, 2010 Comments at 4.

[181] *See*, *e.g*., *PJM Interconnection, L.L.C*., 123 FERC ¶ 61,257 (2008).

[182] *Standards for Business Practices and Communication Protocols for Public Utilities*, Final Rule, 131 FERC ¶ 61,022 (2010).

Phase II standards with more substantive and consistent wholesale standards for measurement and verification.[183]

94. A number of commenters maintain that compensating demand response resources at the LMP during all hours could make determining baselines for demand response providers exceedingly difficult. However, the impact of our adopting the net benefits test described herein is that the LMP will not be paid to demand response resources in all hours. Accordingly, implementation of this Final Rule would not appear to prevent the determination of appropriate baselines. Nonetheless, we direct ISOs and RTOs to review their current requirements in light of the changes in this Final Rule and develop appropriate revisions and modifications, if necessary, to ensure that their baselines remain accurate and that they can verify that demand response resources have performed. Specifically, we direct each RTO and ISO to include as part of the compliance filing required herein, an explanation of how its measurement and verification protocols will continue to ensure that appropriate baselines are set, and that demand response will continue to be adequately measured and verified as necessary to ensure the performance of each demand response resource. If necessary, each RTO and ISO should propose any changes needed to ensure that measurement and verification of demand response will adequately capture the performance (or non-performance) of each participating demand response market participant to be consistent with the requirements of this Final Rule.

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[183] *Id*., at P 32-34.

95. Finally, we agree with ISO-NE IMM that demand reductions that are not genuine may be violations of the Commission's anti-manipulation rules.[184] Allegations of such behavior will continue to be investigated, and when appropriate, sanctions will be brought to bear.

D. Cost Allocation

1. NOPR Proposal

96. In response to the NOPR and September 13, 2010 Technical Conference, many commenters argue that, in order to determine the justness and reasonableness of the proposed compensation level, the corresponding cost allocation must be considered.[185] More specifically, these commenters raise concerns regarding how the costs associated with payment of LMP for demand response will be allocated, or assigned, within an ISO or RTO. Several commenters assert that the issues of cost allocation and net benefits are inherently linked, so that the Commission must address both issues together.[186]

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[184] 18 CFR 1.c (2010).

[185] ISO-NE May 13, 2010 Comments at at 39-40; *see also* May 13, 2010 Comments of: AEP at 6-10; CAISO at 6; ConEd at 2; Hess at 3; ICC at 12; PJM at 8; Potomac Economics at 3; Massachusetts AG at 11; Midwest ISO TOs at 5-6; Midwest TDUs at 13; EEI at 5; NECPUC at 12, 22; NECA at 11; RRI at 6; SDG&G at 3-4.

[186] As further addressed below, several commenters assert that the costs of demand response compensation should be borne by only those market participants determined to have benefitted from the subject load reduction, as determined by some type of net benefits test. *See*, *e.g.*, May 13, 2010 Comments of: ISO-NE at 5-6; NECPUC at 22; PJM at 12-14; P3 at 37-38.

2. Comments

97. Comments reveal five specific methods for cost allocation: (1) assignment of costs to the load serving entity (LSE) associated with the demand response provider, (2) assignment of costs broadly to all purchasing customers, (3) bifurcated assignment of costs with some directly assigned to a LSE and others assigned broadly, (4) directly assign the cost for demand response compensation to the retail customers that bid the demand response into the wholesale market, and (5) the settlement method proposed by CDRI, which incorporates the cost of demand response into the dispatch algorithm. Some commenters argue not for a specific method, but for each regional entity to select and employ a method of its own,[187] and a few other commenters assert that the Commission need not address cost allocation in this proceeding.[188]

98. Some commenters argue that costs should be assigned to the LSE associated with the demand response provider because it is this entity that receives the full benefit of demand response.[189] Others argue

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[187] EPSA May 12, 2010 Comments at 67; Midwest TDUs May 13, 2010 Comments at 1; ODEC May 14, 2010 Comments at 5; Potomac Economics May 14, 2010 Comments at 9-10; RRI May 13, 2010 Comments at 4; SoCal Edison May 13, 2010 Comments at 4 (advocating that the local regulatory authority is the proper entity to regulate cost allocation); Viridity May 13, 2010 Comments at 24; EnerNOC Sept. 13, 2010 Comments at 1; Midwest TDUs Sept. 13, 2010 Comments at 2.

[188] Massachusetts AG May 13, 2010 Comments at 9-10.

[189] PJM May 13, 2010 Comments at 15; Midwest ISO May 13, 2010 Comments at 6; CAISO May 13, 2010 Comments at 6; Detroit Edison May 13, 2010 Comments at 3-4; EEI May 13, 2010 Comments at 5; NUSCO May 13, 2010 Comments at 2; National

that costs should be assigned broadly to all purchasing customers because of the concept of cost causation.[190] Cost causation dictates that the costs of demand response should be allocated directly to those entities that benefit from the demand response service provided.[191] Another method presented involves a bifurcated assignment of costs, with some directly assigned to a LSE and others assigned broadly.[192] The fourth method suggested is to directly assign the costs of demand response to the retail customer that bid the demand response into the wholesale market.[193] Lastly, the settlement algorithm proposed by CDRI adjusts upward the day-ahead price paid by the customers that participate in the day-ahead energy market to account for these costs.[194]

3. Commission Determination

99. When a demand response provider curtails, the RTO experiences a reduction in load with a corresponding reduction in billing units through which

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Grid Sept. 13, 2010 Comments at 2-3; Midwest ISO Oct. 13, 2010 Comments at 4.

[190] NECPUC May 13, 2010 Comments at 22; DC OPC May 13, 2010 Comments at 4; PCA Sept. 10, 2010 Comments at 4; Steel Manufactures Ass'n Sept. 13, 2010 Comments at 5; Ohio Commission Sept. 13, 2010 Comments at 4; Wal-Mart Sept. 14, 2010 Comments at 3.

[191] PJM May 13, 2010 Comments at 9; NECPUC May 13, 2010 Comments at 22; PCA Sept. 10, 2010 Comments at 4.

[192] PJM May 13, 2010 Comments at 12; ISO-NE May 13, 2010 Comments at 5.

[193] DC OPC May 13, 2010 Comments at 4. It concedes that this could be a complex undertaking and would result in billing a retail customer for energy that did not consume. *Id*.

[194] CDRI, Integration of Demand Response Into Day Ahead Markets (Attachment B), May 13, 2010 Comments at 16.

the RTO derives revenue. When the two conditions discussed above are met, however, the RTO must pay LMP to both generators and demand response providers for the resources that clear the energy market. The difference between the amount owed by the RTO to resources, including demand response providers, and the revenue it derives from load results in a negative balance that must be addressed through cost allocation. Therefore, a method is needed to ensure that RTOs and ISOs recover the costs of obtaining demand response.

100. Since the dispatch of demand response resources affects the LMP charged, and will result in a lower LMP, the customers benefitting from that lower LMP depends upon transmission constraints, and the price separation such constraints cause within the RTO. In some hours in which transmission constraints do not exist, RTOs establish a single LMP for their entire system (a single pricing area) in which case the demand response would result in a benefit to all customers on the system. When transmission constraints are present, however, LMPs often vary by zone, or other geographic areas. Allocating the costs associated with demand response compensation proportionally to all entities that purchase from the relevant energy market in the area(s) where the demand response resource reduces the market price for energy at the time when the demand response resource is committed or dispatched will reasonably allocate the costs of demand response to those who benefit from the lower prices produced by dispatching demand response.[195]

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[195] This approach is consistent with long-standing judicially-endorsed cost allocation principles. *See*, *e.g.*, *Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1368, 1370-71

101. We reject the various other methods of cost allocation suggested by commenters. Assignment of all costs to the LSE associated with the demand response provider, as suggested by some commenters, would not include others who benefit from the demand response. Bifurcated assignment of costs to the LSE and to others appears to represent an arbitrary division of cost responsibility without regard to the degree to which each receives benefits.

102. We therefore find just and reasonable the requirement that each RTO and ISO allocate the costs associated with demand response compensation proportionally to all entities that purchase from the relevant energy market in the area(s) where the demand response reduces the market price for energy at the time when the demand response resource is committed or dispatched. Accordingly, each RTO and ISO is required to make a compliance filing on or before July 21, 2011 that either demonstrates that its current cost allocation methodology appropriately allocates costs to those that benefit from the demand reduction or proposes revised tariff provisions that conform to this requirement.

E. Commission Jurisdiction

1. Comments

103. Some commenters, including several state commissions and LSEs, express concern about whether and how standardizing demand response compensation in the wholesale market will affect treatment of demand response at the retail level. They assert that the issue of demand response

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(D.C. Cir. 2004); *see also Illinois Commerce Comm'n v. FERC*, 576 F.3d 470, 476 (7th Cir. 2009).

compensation is fundamentally intertwined with retail rates, ratepayer issues, and state jurisdictional concerns.[196] Some commenters note general concerns about the need for federal and state level coordination. They assert that many states have taken significant steps to install advanced meters and implement programs to encourage efficient use of energy and that the success of state-level efforts should be a factor in deciding whether and how to implement demand response programs in the wholesale market.[197] According to these commenters, a Commission-mandated compensation level could have the unintended consequence of retarding the expansion of price-responsive demand at the retail level.[198]

104. Other commenters flatly question the Commission's jurisdiction to set the compensation for demand response in wholesale energy markets. They argue that it is within the purview of retail regulatory authorities to take into account local policies and concerns, and the types of demand response being offered, when determining the appropriate compensation level.[199] Indeed, the California Commission

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[196] *See*, *e.g*., CAISO May 13, 2010 Comments at 12; PJM May 13, 2010 Comments at 8 (appropriate and efficient demand response compensation may require coordination between the Commission, retail regulatory authorities, competitive retail suppliers, and other RTOs).

[197] *See* ISO-NE IMM May 13, 2010 Comments at 6.

[198] Illinois Commission May 13, 2010 Comments at 8; PJM May 13, 2010 Comments at 23; EEI May 13, 2010 Comments at 4; Capital Power May 13, 2010 Comments at 5; ODEC May 13, 2010 Comments at 60; Steel Producers May 13, 2010 Comments at 2.

[199] *See* Illinois Commission May 13, 2010 Comments at 13; CAISO May 13, 2010 Comments at 12-13; PJM IMM May 13, 2010 Comments at 5 ("The assertion that demand side participants should be paid full LMP, regardless of their retail

seeks clarification that this Commission does not seek to regulate retail customer rates or seeks LSE oversight authority traditionally exercised by states. The California Commission asserts that this Commission's actions concerning CAISO's Proxy Demand Resource tariff filing [200] illustrates that demand response settlement mechanisms are within the authority of the California Commission.[201]

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tariff rate, because the current approach of paying LMP minus G represents an intervention into retail rate design, cannot be correct. The entire demand side program exists only because of the disconnect between wholesale and retail rates. The assertion that the program design should not account for the details of retail rate design leads to the conclusion that there should be no demand side program at all."); NECPUC May 13, 2010 Comments at 25 ("As energy market customers benefit most from both a well-functioning wholesale market and robust participation in retail programs, a balance between these two segments is essential. Compensation that increases demand response resource participation in the wholesale market should not be so generous, from the perspective of the customer, that it makes participation in retail programs pale in comparison."); SDG&E, SoCal Edison, and PG&E May 13, 2010 Comments at 4 ("[M]andating that ISOs take on settlement responsibility or precluding any retail settlement between retail customers, LSEs or DRPs would intrude on retail jurisdictional authority and contravenes the premise of separation outlined in Order 719."); Consumers Energy May 13, 2010 Comments at 3; Detroit Edison May 13, 2010 Comments at 4.

[200] *See California Independent System Operator Corp*., 132 FERC ¶ 61,045 (2010).

[201] California Commission May 13, 2010 Comments at 9-10. 1. [sic] *See also* SDG&E, SCE, PG&E May 13, 2010 Comments at 2 ("[T]he Commission should clarify that its order does not preclude LRAs from administering retail revenue settlements between retail customers, Load Serving Entities (LSEs) and Demand Response Providers (DRPs) associated with DR participation in wholesale markets.").

105. Other commenters foresee retail regulatory authorities effectively taking an end-run around any Commission-mandated compensation level by adjusting retail rate design or prohibiting jurisdictional end-use customers from participating in wholesale market opportunities available to demand response resources.[202] The Illinois Commission argues:

> [W]hen load serving entities are vertically integrated with generation regulated under state authority . . . any non-zero payment to a demand response resource reduces the revenues to generators under the state regulatory authority. The result is a leakage of money to an entity outside of the state's regulatory authority. Therefore, retail rates to all customers may need to be increased in order to recover the costs to generators that would have otherwise been recovered through the purchase of electricity, but instead went to the payment of a demand response resource. Therefore, compensating demand response resources may increase the

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[202] *See* PJM May 13, 2010 Comments at 24; PJM May 13, 2010 Comments at 18 (It is reasonable to assume that each retail regulatory authority in PJM will re-examine the impact of load reduction based on wholesale compensation equal to the LMP, including cost allocation, on the LSEs subject to its jurisdiction, and potentially re-align retail market rules affecting economic load response participation.); Delaware Commission and NECPUC May 13, 2010 Comment at 25; OMS May 13, 2010 Comments at 7 (state commissions and LSEs have significant concerns that the potential costs for non-participating customers may exceed the benefits that ARCs can provide to their states and to participating customers, so state commissions will have a significant disincentive to support the participation of ARCs in RTO energy markets and in their states if LMP compensation is adopted).

> likelihood that state commissions will prohibit the participation of demand response resources in the jurisdictions.[203]

106. Similarly, PJM states that the prohibition devised by retail regulatory authorities with jurisdiction over smaller distributors that deliver 4 million MWh or fewer per annum may entail the revocation of previously provided permission to participate in some or all of the wholesale market opportunities for demand resources.[204]

107. Some commenters further posit that, even where retail regulatory authorities do not prohibit or limit demand response participation, they may make adjustments to the retail rate, which affect the ultimate compensation that the retail customer will be paid for its demand reductions.[205] For example, the OMS asserts,

> If the Commission were to adopt the proposed rule, state commissions and LSEs could correct this distorted price signal by revising retail tariffs for customers that do business with [aggregators of retail customers] in order to charge the retail rate to participating customers for energy which was not consumed or metered as a result of load reductions.[206]

108. Another set of commenters, especially generators, assert that due to the disconnect between wholesale and retail issues related to demand response,

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[203] Illinois Commission May 13, 2010 Comments at 15.

[204] PJM May 13, 2010 Comments at 20-21.

[205] CAISO May 13, 2010 Comments at 4.

[206] OMS May 13, 2010 Comments at 3. *See also* EEI May 13, 2010 Comments at 4.

Commission-mandated payments for demand response will fail to address true barriers to demand response, which exist, they assert, at the retail level. These commenters argue that the Commission's actions in this proceeding ignore the fact that the primary barrier to demand response is the disconnect between retail and wholesale prices and, according to these commenters, the remedy resides at the retail—not wholesale—level where there is a lack of dynamic pricing.[207] For example, some commenters recognize that the lack of retail real-time pricing is a barrier to demand response participation but further assert that whatever changes the Commission makes to wholesale demand response (where there is real-time pricing) will not address that fundamental problem.[208]

109. On the other hand, some commenters, such as commercial customers, wholly reject challenges to the

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[207] Calpine May 13, 2010 Comments at 3.

[208] *See* EPSA May 13, 2010 Comments at 7 ("The NOPR incorrectly attempts to resolve retail market barriers to DR participation (i.e., lack of dynamic pricing) through a wholesale pricing fix."); RRI Energy May 13, 2010 Comments at 5 ("The NOPR is essentially trying to use an inefficient wholesale solution to remedy a retail problem. The NOPR does not attempt to address (nor should it attempt to address) the various retail rate structures that demand response providers in various regions of the country face."); The Brattle Group May 13, 2010 Comments at 8 ("[T]he appropriate avoidable retail generation rate is best done through agreements between the LSE and the curtailment service provider under the oversight of the relevant retail regulating authority. This approach. . . avoids requiring the RTO to sort through potentially complicated retail rate structures."); Steel Manufacturers Ass'n May 13, 2010 Comments at 9 ("[T]here is no rational basis for the Commission, or RTOs, to adopting varying demand response participation or compensation rules based on the retail pricing method of otherwise qualified participating loads.").

Commission's authority to set the compensation level for demand response occurring in organized wholesale energy markets.[209] They assert that the FPA gives the Commission broad authority to correct market flaws, including compensation for demand response.[210]

110. Some commenters further argue that any disconnect between wholesale and retail issues relevant to demand response should not negate the Commission's efforts in this proceeding. They argue that dynamic retail pricing, retail shopping opportunities and the potential for retail energy efficiency measures are no substitute for adequate wholesale demand response compensation and the deployment of demand response measures akin to a generator.[211]

111. Moreover, some commenters assert that, while the Commission has authority to establish the compensation level for demand response in the wholesale market, the Commission cannot require subtraction of retail rate components from the LMP rate, reasoning that retail rates reflect a myriad of local concerns beyond the Commission's jurisdiction. These commenters assert that LMP reflects the wholesale value of the demand response service provided and that proponents of the LMP-G formulation (subtracting a portion of the retail rate) seek to draw the Commission into a review of retail rate matters beyond its purview.[212] Additionally, these commenters point to the difficulty of isolating the generation component of the retail rate from other components, such as transmission, distribution, and

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[209] DR Supporters Aug. 30, 2010 Reply Comments at 4.

[210] *Id.*

[211] Wal-Mart May 13, 2010 Comments at 11.

[212] Viridity June 18, 2010 Comments at 13.

overhead. They argue that different retail rate contracts reflect different costs of generation, depending on local circumstances existing at the time the contract was executed, and that retail rate structures reflect a wide range of competing considerations, such as cost causation, the impact of rate design on employment, and the state of the local economy, all of which are appropriately left to state commissions. These commenters posit that, instead of tailoring the wholesale rate, i.e., LMP, to retail rate conditions, it is better to get the wholesale rate right in the first instance and then allow retail rate structures adjust as needed to wholesale market conditions.[213] According to Dr. Kahn, accounting for the retail rate in this Final Rule would "ignore the proper scope of the Commission's regulatory responsibilities, the fact that the great majority of retail rate designs are economically inefficient and that it is retail rates that should not be permitted to undermine efficient wholesale rates rather than the reverse."[214]

2. Commission Determination

112. We begin by rejecting challenges to the Commission's authority to set the compensation level for demand response in organized wholesale energy markets. Section 205 of the FPA tasks the Commission with ensuring that all rates and charges for or "in connection with" the transmission or sale for resale of electric energy in interstate commerce, and all rules and regulations "affecting or pertaining to" such rates or charges are just and reasonable.[215] The Commis-

[213] Viridity June 18, 2010 Comments at 14.

[214] DR Supporters Aug. 30, 2010 Comments (Kahn Affidavit at 4).

[215] 16 U.S.C. 824d (2006).

sion has previously explained that it has jurisdiction over demand response in organized wholesale energy markets, because it directly affects wholesale rates.[216]

113. For this reason, the Commission has jurisdiction to regulate the market rules under which an ISO or RTO accepts a demand response bid into a wholesale market.[217] Furthermore, as discussed above, the Commission's actions in this proceeding are consistent with Congressional policy requiring federal level facilitation of demand response, because this Final Rule is designed to remove barriers to demand response participation in the organized wholesale energy markets.

114. Nevertheless, we recognize that jurisdiction over demand response is a complex matter that lies at the confluence of state and federal jurisdiction. By issuing this Final Rule, the Commission is not requiring actions that would violate state laws or regulations. The Commission also is not regulating retail rates or usurping or impeding state regulatory efforts concerning demand response.

115. We acknowledge that many barriers to demand response participation exist and that our ability to address such barriers is limited to the confines of our statutory authority. At the same time, the FPA requires the Commission to ensure that the rates charged for energy in wholesale energy markets are just, reasonable, and not unduly discriminatory or preferential. The Commission has the authority, indeed the responsibility, to assure that wholesale rates are just and reasonable. Therefore, we disagree

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[216] Order No. 719-A, FERC Stats. & Regs. ¶ 31,292 at P 47.

[217] Order No. 719-A, FERC Stats. & Regs. ¶ 31,292 at P 52.

with commenters who would have the Commission refrain from acting on demand response compensation in the organized wholesale energy markets because of the potential actions that state retail regulatory authorities may or may not take. As we note above, this Final Rule is not intended to usurp state authority or impede states from taking any actions within their authority. Rather, the Commission is taking action here to fulfill its statutory mandate to ensure just, reasonable, and not unduly discriminatory or preferential wholesale rates.

V. Information Collection Statement

116. The Office of Management and Budget (OMB) requires that OMB approve certain information collection and data retention requirements imposed by agency rules.[218] Therefore, the Commission is submitting the proposed modifications to its information collections to OMB for review and approval in accordance with section 3507(d) of the Paperwork Reduction Act of 1995.[219]

117. OMB's regulations require approval of certain information collection requirements imposed by agency rules. 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 a 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.

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[218] 5 CFR § 1320.11(b) (2010).

[219] 44 U.S.C. § 3507(d) (2006).

118. The Commission is submitting these reporting requirements to OMB for its review and approval under section 3507(d) of the Paperwork Reduction Act. Comments are solicited 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.

Burden Estimate and Information Collection Costs: The estimated Public Reporting burden and cost for the requirements contained in the final rule follow.

FERC-516 Data Collection	Number of Respondents (a)	No. of Responses Per Respondent Per Year (b)	Hours Per Response (c)	Total Annual Hours (d) [a*b*c]
Compliance filing, including tariff provisions and analysis (one-time filing, due 7/22/2011)	6 (RTOs and ISOs)	1 (one-time filing)	300	1,800 (one-time filing)
Study on dynamic net benefits approach (one-time filing, due 9/21/2012)	6 (RTOs and ISOs)	1 (one-time filing)	2,000	12,000 (one-time filing)

Monthly update to price threshold and web posting (due monthly, starting after the compliance filing due 7/22/2011)	6 (RTOs and ISOs)	12	50	3,600

In Year 1, the following requirements are imposed[220]: (1) compliance filing due on or before July 22, 2011, and (2) monthly updates (for months 5-12, and starting after the compliance filing). The total corresponding burden hours are estimated to be: 1,800 hrs. + (8 filings * 6 respondents * 50 hrs./filing), for a total of 4,200 hours. The corresponding total cost is estimated to be: 4,200 hours * $220/hour, for a total of $924,000.

In Year 2, (a) the monthly update to the price threshold, and (b) the study on dynamic net benefits approach (due on or before September 21, 2012) are imposed. The corresponding total burden is estimated to be 3,600 + 12,000 hours, for a total of 15,600 hours. The corresponding total cost estimate is: 15,600 hours * $220/hour, for a total of $3,432,000.

In Year 3, the monthly update to the price threshold is imposed. The corresponding total burden and cost

[220] The one-time study is due on or before September 21, 2012. For the purpose of the burden and cost estimates, we are including all of the burden and cost related to the study in Year 2, although filers may perform part of the work in Year 1.

are estimated to be 3,600 hours and $792,000 (3,600 hours * $220/hour).

Title: FERC-516, "Electric Rate Schedules and Tariff Filings"

Action: Proposed Collections.

OMB Control No: 1902-0096.

Respondents: Business or other for profit, and/or not for profit institutions.

Frequency of Responses: One-time filings for (a) the compliance filing, due on or before July 22, 2011, and (b) the study on dynamic net benefits approach, due on or before September 21, 2012. In addition, monthly updates to the price threshold and web posting will be required starting after the compliance filing.

Necessity of the Information: The information from FERC-516 enables the Commission to exercise its statutory obligation under sections 205 and 206 of the FPA. FPA section 205 specifies that all rates and charges, and related contracts and service conditions for wholesale sales and transmission of energy in interstate commerce be filed with the Commission and must be "just and reasonable." In addition, FPA section 206 requires the Commission, upon complaint or its own motion, to modify existing rates or services that are found to be unjust, unreasonable, unduly discriminatory or preferential.

119. In Order No. 719, the Commission emphasized the importance of demand response as a vehicle for improving the competitiveness of organized wholesale electricity markets and ensuring supplies of energy at just, reasonable and not unduly discriminatory or preferential rates. This Final Rule addresses the need for organized wholesale energy markets to provide

compensation to demand response resources on a comparable basis to supply-side resources when demand response resources are comparable to supply-side resources, so that both supply and demand can meaningfully participate. This final rule establishes a specific compensation approach for demand response resources participating in organized wholesale energy markets, administered by RTOs and ISOs. Each Commission-approved RTO and ISO that has a tariff provision providing for participation of demand response resources in its organized wholesale energy market must: (a) pay demand response resources the market price (full LMP) for energy (when found to be cost-effective as determined by the net benefits test described herein), (b) submit a one-time compliance filing, (c) perform monthly updates to the Price Threshold, and (d) submit a one-time Study on Dynamic Net Benefits Approach.

120. Interested persons may obtain information on the reporting requirements by contacting: Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 [Attention: Ellen Brown, Information Clearance Officer, Office of the Executive Director, e-mail: DataClearance@ferc.gov, phone: (202) 502-8663, fax: (202) 273-0873]. Comments on the requirements of the final 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]. For security reasons, comments to OMB should be submitted by e-mail to: oirasubmission@omb.eop.gov. Comments submitted to OMB should include Docket Number RM10-17 and OMB Control Number 1902-0096.

VI. Environmental Analysis

121. 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.[221] 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.[222]

VII. Regulatory Flexibility Act

122. The Regulatory Flexibility Act of 1980 (RFA)[223] generally requires a description and analysis of final rules that will have significant economic impact on a substantial number of small entities. The RFA mandates consideration of regulatory alternatives that accomplish the stated objectives of a rule and that minimize any significant economic impact on a substantial number of small entities. The Small Business Administration's (SBA) Office of Size Standards develops the numerical definition of a small

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[221] *Regulations Implementing the National Environmental Policy Act*, Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs., Regulations Preambles 1986-1990 ¶ 30,783 (1987).

[222] 18 CFR § 380.4(a)(15) (2010).

[223] 5 U.S.C. § 601-612 (2006).

business.[224] The SBA has established a size standard for electric utilities, stating that a firm is small if, including its affiliates, it is primarily engaged in the transmission, generation and/or distribution of electric energy for sale and its total electric output for the preceding twelve months did not exceed four million megawatt hours.[225] ISOs and RTOs, not small entities, are impacted directly by this rule.

123. California Independent System Operator Corp. (CAISO) is a non-profit organization with over 54,000 megawatts of capacity and over 25,000 circuit miles of power lines.

124. New York Independent System Operator, Inc. (NYISO) is a non-profit organization that oversees wholesale electricity markets, dispatches over 500 generators, and manages a nearly 11,000-mile network of high-voltage lines.

125. PJM Interconnection, L.L.C. (PJM) is comprised of more than 600 members including power generators, transmission owners, electricity distributors, power marketers, and large industrial customers, serving 13 states and the District of Columbia.

126. Southwest Power Pool, Inc. (SPP) is comprised of 61 members serving over 6.2 million households in nine states and has almost 50,000 miles of transmission lines.

127. Midwest Independent Transmission System Operator, Inc. (Midwest ISO) is a non-profit organization with over 145,000 megawatts of installed generation. Midwest ISO has over 57,000 miles of

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[224] 13 CFR § 121.101 (2010).

[225] 13 CFR § 121.201, Sector 22, Utilities.

transmission lines and serves 13 states and one Canadian province.

128. ISO New England, Inc. (ISO-NE) is a regional transmission organization serving six states in New England. The system is comprised of more than 8,000 miles of high-voltage transmission lines and over 350 generators.

129. The Commission believes this rule will not have a significant economic impact on a substantial number of small entities, and therefore no regulatory flexibility analysis is required.

VIII. Document Availability

130. 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 the Commission's Home Page (http://www.ferc.gov) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington DC 20426.

131. From the Commission'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.

132. User assistance is available for eLibrary and the Commission's website during normal business hours from FERC Online Support at 202-502-6652 (toll free at 1-866-208-3676) or email at ferconlinesup

port@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.

IX. Effective Date and Congressional Notification

133. This Final Rule will become effective on [INSERT DATE 30 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs, Office of Management and Budget, that this rule is not a "major rule" as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996.

By the Commission. Commissioner Moeller dissenting with a separate statement attached.

(SEAL)

Kimberly D. Bose,
Secretary.

In consideration of the foregoing, the Commission proposes to amend Part 35,

Chapter I, Title 18, 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.

2. Amend § 35.28 as follows:

Add a new paragraph (g)(1)(v).

§ 35.28 Non-discriminatory open access transmission tariff.

* * * * *

(v) *Demand response compensation in energy markets*. Each Commission-approved independent system operator or regional transmission organization that has a tariff provision permitting demand response resources to participate as a resource in the energy market by reducing consumption of electric energy from their expected levels in response to price signals must:

(A) pay to those demand response resources the market price for energy for these reductions when these demand response resources have the capability to balance supply and demand and when payment of the market price for energy to these resources is cost-effective as determined by a net benefits test accepted by the Commission;

(B) allocate the costs associated with demand response compensation proportionally to all entities that purchase from the relevant energy market in the area(s) where the demand response reduces the market price for energy at the time when the demand response resource is committed or dispatched.

Note: The following appendix will not be published in the Code of Federal Regulations.

APPENDIX

List of Commenters

Alcan Primary Products Corp. (Alcan)

Alcoa Inc. (Alcoa)

Alliance for Clean Energy New York, Inc. (ACENY)

Alliance to Save Energy (Alliance)

American Chemistry Council (ACC)

American Clean Skies Foundation

American Council for an Energy-Efficient Economy (ACEEE)

American Electric Power Service Corporation (AEP)

American Forest & Paper Association (AFPA)

American Municipal Power, Inc. (AMP)

American Public Power Association (APPA)

American Wind Energy Association (AWEA)

ArcelorMittal USA Inc. (ArcelorMittal)

Battelle Pacific Northwest Laboratories (Battelle)

Boston College Law School Administrative Law Class (BC Law)

California Department of Water Resources State Water Project (CDWR)

California Independent System Operator Corporation (CAISO)

California Public Utilities Commission (California Commission)

Calpine Corp. (Calpine)

Capital Power Corporation (Capital Power)

Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California (Six Cities)

Citizens for Pennsylvania's Future (PennFuture)

Coalition of Midwest Transmission Customers (CMTC)

Connecticut Municipal Electric Energy Cooperative (CMEEC)

Consert Inc. (Consert)

Conservation Law Foundation (CLF)

Consolidated Edison Solutions, Inc. (ConEd)

Constellation Energy Commodities Group, Inc. (Constellation)

Consumer Demand Response Initiative (CDRI)

Consumer Power Advocates (CPA)

Consumers Energy Company (Consumers Energy)

CPG Advisors, Inc. (CPG)

CPower, Inc. (CPower)

Crane & Co., Inc. (Crane)

Delaware Public Service Commission (Delaware Commission)

Demand Response and Smart Grid Coalition (Smart Grid Coalition)

Demand Response Supporters (DR Supporters)

Derstine's Inc. (Derstine's)

Detroit Edison Company (Detroit Edison)

Direct Energy Services, LLC (Direct Energy)

Dominion Resources Services, Inc. (Dominion)

Dr. Alfred E. Kahn (Dr. Kahn)

Dr. Charles J. Cicchetti (Dr. Cicchetti)

Dr. Roy J. Shanker (Dr. Shanker)

Dr. William W. Hogan (Dr. Hogan)

Duke Energy Corporation (Duke Energy)

Durgin and Crowell Lumber Co., Inc. (Durgin)

Edison Electric Institute (EEI)

Edison Mission Energy (Edison Mission)

Electric Power Supply Association (EPSA)

Electricity Committee

Electricity Consumers Resource Council (ELCON)

Electrodynamics, Inc. (Electrodynamics)

Energy Curtailment Specialists, Inc. (ECS)

EnergyConnect (EnergyConnect)

Energy Future Coalition (EFC)

EnerNOC, Inc. (EnerNOC)

Environmental Defense Fund (EDF)

Exelon Corporation (Exelon)

Federal Trade Commission (FTC)

FirstEnergy Service Company (FirstEnergy)

GDF SUEZ Energy North America, Inc. (GDF)

Hess Corporation (Hess)

Illinois Citizens Utility Board (Illinois CUB)

Illinois Commerce Commission (ICC)

Independent Power Producers of New York, Inc. (IPPNY)

Indicated New York Transmission Owners (Indicated New York TOs)

Industrial Energy Consumers of America (IECA)

Industrial Energy Consumers of Pennsylvania (IECPA)

Intergrys Energy Services, Inc. (Intergrys)

International Power America, Inc. (IPA)

Irving Forest Products, Inc. (Irving Forest)

ISO New England Inc. (ISO-NE)

ISO-NE Internal Market Monitor (ISO-NE IMM)

Jiminy Peak Mountain Resort, LLC

Joint Consumer Advocates (Joint Consumers)

Limington Lumber (Limington)

Madison Paper Industries (Madison Paper)

Maryland Governor Martin O'Malley (Governor O'Malley)

Maryland Public Service Commission (Maryland Commission)

Massachusetts Attorney General (Massachusetts AG)

Midwest Independent Transmission System Operator, Inc. (Midwest ISO)

Midwest ISO Transmission Owners (Midwest ISO TOs)

Midwest TDUs

Mirant Corporation (Mirant)

Monitoring Analytics, LLC (PJM IMM)

National Electrical Manufactures Association (NEMA)

National Energy Marketers Association (NEM)

National Grid USA (National Grid)

National League of Cities (NLC)

Natural Gas Supply Association (NGSA)

New England Conference of Public Utilities Commissioners (NECPUC)

New England Consumer Advocates (NECA)

New England Power Generators Association Inc. (NEPGA)

New England Power Pool Participants Committee (NEPOOL)

New England Public Systems (NE Public Systems)

New Jersey Board of Public Utilities (NJBPU)

New York Independent System Operator, Inc. (NYISO)

New York Mayor Michael R. Bloomberg (Mayor Bloomberg)

New York State Consumer Protection Board (NYSCPB)

New York State Public Service Commission (New York Commission)

North America Power Partners LLC (NAPP)

Northeast Utilities Services Company (NUSCO)

Northern California Power Agency (NCPA)

NSTAR Electric Company (NSTAR)

Occidental Chemical Corp. (Occidental)

Office of the People's Counsel for the District of Columbia (DC OPC)

Okemo Mountain Resort (Okemo)

Old Dominion Electric Cooperative (ODEC)

Organization of Midwest ISO States (OMS)

Partners HealthCare (Partners)

Pennsylvania Department of Environmental Protection (PA Department of Environment)

Pennsylvania Office of Consumer Advocate (PCA)

Pennsylvania Public Utility Commission (Pennsylvania Commission)

Pennsylvania State Representative Chris Ross (Rep. Ross)

Pepco Holdings, Inc. (PHI)

PJM Interconnection, L.L.C. (PJM)

PJM Power Providers Group (P3)

Potomac Economics, Ltd. (Potomac Economics)

PPL Parties (PPL)

Praxair, Inc. (Praxair)

Precision Lumber, Inc. (Precision)

Price Responsive Load Coalition (PRLC)

PSEG Companies (PSEG)

Public Interest Organizations (PIO)

Public Utilities Commission of Ohio (Ohio Commission)

Raritan Valley Community College (Raritan)

Robert J. Borlick (Mr. Borlick)

RRI Energy, Inc. (RRI)

San Diego Gas & Electric Company (SDG&E)

Schneider Electric USA, Inc. (Schneider)

Southern California Edison Company (SoCal Edison)

Southwest Power Pool, Inc. (SPP)

Steel Manufacturers Association (Steel Manufacturers Ass'n)

Steel Producers (SP)

Tendrill Networks, Inc. (Tendrill)

The Brattle Group

The E Cubed Company, L.L.C. (E3)

University of California, San Diego (UCSD)

Utility Economic Engineers (UEE)

Verso Paper Corp. (Verso)

Virginia Committee for Fair Utility Rates (Virginia Committee)

Viridity Energy, Inc. (Viridity)

Wal-Mart Stores, Inc. (Wal-Mart)

Waterville Valley Ski Resort Inc. (Waterville)

Westar Energy, Inc. (Westar)

Wisconsin Industrial Energy Group (WIEG)

MOELLER, Commissioner, dissenting:

While the merits of various methods for compensating demand response were discussed at length in the course of this rulemaking, nowhere did I review any comment or hear any testimony that questioned the benefit of having demand response resources participate in the organized wholesale energy markets. On this point, there is no debate. The fact is that demand response plays a very important role in these markets by providing significant economic, reliability, and other market-related benefits.

However, in a misguided attempt to encourage greater demand response participation in the organized energy markets, today's Rule imposes a standardized and preferential compensation scheme that conflicts both with the Commission's efforts to promote competitive markets and with its statutory mandate to ensure supplies of electric energy at just, reasonable, and not unduly discriminatory or preferential rates.[226] For these reasons, I cannot support this Rule.

Standardizing Demand Response Compensation

As an initial matter, RTOs and ISOs currently offer different types of demand response products that vary from region to region and in terms of capability and services offered in the day-ahead and real-time energy markets. Moreover, the RTOs and ISOs to date have been working with their market participants in a stakeholder process to design demand response compensation rules that are tailored to suit the needs of their individual energy markets. However, this will

[226] 16 U.S.C. § 824d (2006).

all change once the Rule takes effect and this existing framework is replaced with the requirement that every organized wholesale energy market pay demand resources the market price for energy (LMP) when its demand reductions are, in theory, found to be cost-effective.

As I recognized in my initial statement in this proceeding, organized markets such as the PJM Interconnection have already demonstrated the ability to develop demand response compensation rules. Accordingly, I would have preferred to allow these markets to continue to develop their own rules. Different demand response products will have different values that reflect their varying capabilities and to require a standard payment fails to reflect these meaningful differences.[227]

However, without ever determining that the existing region-by-region approach to compensation is unjust and unreasonable, the Rule implies that the current approach is no longer adequate to ensure that rates remain just and reasonable. In turn, the Rule finds that "greater uniformity in compensating demand response resources" is required and as justification for its action, references the existence of various barriers that limit the participation of demand

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[227] California Commission May 13, 2010 Comments at 6, "[P]romulgating a uniform national rule at this time may inadvertently impede the implementation of optimal demand response compensation for an individual ISO or RTO which address the needs of that particular region." The California Commission "is concerned that mandatory 'one size fits all' pricing may stifle national and regional efforts to collect valuable data and experience regarding the effects of different demand response program designs on consumer participation and conflict with Congressional objectives."

response in the energy markets.[228] The majority ultimately concludes that these barriers can be removed by better equipping demand response providers with the financial resources to invest in enabling technologies.[229] This is to say that the majority believes that paying demand resources more money will help overcome these barriers and encourage more participation. The Rule, however, never clearly explains how the existence of barriers, in turn, justifies a payment of full LMP to demand resources.

The Rule (like the NOPR) does not sufficiently discuss the need for standardizing compensation across the organized markets or elaborate on how standardization will remove genuine barriers that prevent meaningful participation by demand resources in the energy markets.[230] While the Energy Policy Act of 2005 states that the policy of the U.S. Government is to remove unnecessary barriers to demand response, the statute never authorized the Commission to stimulate increased demand response participation by requiring its compensation to include incentives or preferential treatment.[231] Although, the majority is quick to claim "that removing barriers to demand response participation is not the same as giving preferential treatment to demand response providers. . .", this is exactly what is occurring in this

[228] Rule at P 17, 57-59.

[229] Rule at P 57-59.

[230] Significant barriers do exist which prevent demand response from reaching its full potential. Specifically, 24 barriers were identified in our *National Assessment of Demand Response Potential*, FERC Staff Report, (June 2009) at 65-67.

[231] *See* Energy Policy Act of 2005, Pub. L. No. 109-58, § 1252(f), 119 Stat. 594, 965 (2005).

Rule.[232] As discussed below, the majority's determination is troubling as the Rule both affords preferential treatment to demand response resources and unduly discriminates against them in other respects.

Demand Response Resources are Comparable . . . Sometimes

At the outset, the concept of "comparability" is at the core of this rulemaking, *i.e*., whether demand response resources are capable of providing a service comparable to generation resources and if so, whether these resources should receive comparable compensation for a comparable service. On this point, I believe they should.[233] This is not to say that a megawatt produced is the same as a megawatt not consumed; they are not perfect equivalents. The characteristics of a megawatt and a "negawatt" are different, both in terms of physics and in economic impact.

Assuming, however, that a demand resource can provide a balancing service that is identical to that of a generation resource, it would make sense that a demand resource providing a comparable service would receive comparable compensation. But this may not occur under the Rule. The majority explains that if a demand resource is capable of providing a service comparable to a generation resource, it will only be eligible to receive comparable compensation, by definition, if it can also be determined that the

[232] Rule at P 59.

[233] As explained below, I believe that comparable compensation is represented by the value realized by the demand resource for providing a comparable service, regardless of whether the source of that value is a payment from the market or a savings by the resource.

resource will result in a price-lowering effect to the market by passing a net benefits test.[234]

In no other circumstance is a resource required to show that its participation will depress the market price in order to receive comparable compensation for a comparable service.[235] Such a definition unduly discriminates against demand resources and as such, this requirement is unjust, unreasonable, and unduly discriminatory.

Overcompensating Demand Resources and the Net Benefits Test

At first glance, the Rule's requirement that RTOs and ISOs pay demand response resources the LMP only when it is deemed cost-effective appears to make sense. There is near-universal agreement that the LMP reflects the value of the marginal unit, and as such, it sends the proper price signal to keep supply and demand in relative balance. Accordingly, the Rule explains that if the demand resource is capable of providing a comparable service and is also cost-effective (i.e., using a net benefits test to ensure that the overall benefit of the reduced LMP that results from dispatching demand recourses exceeds the cost of dispatching those resources), then this resource should be paid the same as a generation resource. However, the decision to pay demand resources the full LMP under such circumstances actually results in overcompensation that is economically inefficient,

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[234] Rule at P 47-50.

[235] Testimony of Audrey Zibelman, President and CEO of Viridity Energy, Inc., Sept. 13, 2010 Tr. at 119, "[T]he fact that we're debating this [net benefits test] is somewhat absurd. We have not required any other resource to demonstrate a benefit in order to enter this market."

preferential to demand resources, and unduly discriminatory towards other market resources.

An example may help to illustrate a major flaw with this Rule. Assume that both a generation resource and a demand resource bid into the energy market and both bids are accepted and paid the LMP ($100). Then consider the fact that the demand resource will save an amount that it would have otherwise paid by not purchasing generation at the retail rate ("G"), which is $25. While the Rule requires that RTOs and ISOs pay the demand resource the LMP (which is the identical amount the generation resource receives), the Rule effectively ignores the fact that the demand resource will actually receive a total compensation of LMP+G ($125) as a result of its decision not to consume.[236] Meanwhile, the generation resource will only receive the LMP ($100) payment as a result of its decision to produce. While the Rule's intent is to ensure that a demand resource receives "the same compensation, the LMP, as a generation resource", this is not the actual result.[237] In this example, what will happen is that the Rule will require that the demand response resource be overcompensated by $25.[238]

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[236] The proper economic measure of value realized by the demand resource is one where the RTO or ISO makes a reduction from the LMP to account for the retail rate, but then recognizes that the savings associated with the avoided retail generation cost should be added back into the equation, *i.e*., (LMP-G)+G.

[237] Rule at P 82. If it were the result, the generation resource would be paid the LMP, $100, and the demand resource would be paid $75 and realize an additional $25 in retail rate savings. Accordingly, both resources realize equivalent compensation valued at $100.

[238] Ohio Commission May 13, 2010 Comments at 6, "[T]he Commission's proposal that RTOs pay demand response

The Rule effectively finds that demand resources being compensated at the *value* of full LMP is not enough, so instead requires that demand resource be *paid* the full LMP plus be allowed to retain the savings associated with its avoided retail generation cost. Professor William W. Hogan refers to this outcome as a "double-payment" because demand resources would "receive" both the cost savings from not consuming electricity at a particular price, plus an LMP payment for not consuming that same increment of electricity.[239] Not only is this result not comparable (by valuing a negawatt more than a megawatt) and economically inefficient (by distorting the price signal), but this preferential compensation will harm the efficiency of the competitive wholesale energy markets.

The use of a net benefits test further reduces competitive efficiency and only complicates the issue. As the Rule explains, the net benefits test involves the determination of a threshold price point that is plotted along a historical supply curve in an attempt to accurately calculate whether the cost of procuring additional demand response is outweighed by the value it brings to the market in the form of a lower LMP.[240] However, this test, which attempts to justify

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resources the full LMP takes the incentives for wholesale demand response resources a step too far. It would provide an incentive to the supplier of a demand response resource that exceeds the payments available to an equivalent supply resource. The Commission should instead focus on removing the existing barriers in the wholesale markets . . . ."

[239] *See* Attachment to Answer of EPSA, Providing Incentives for Efficient Demand Response, Dr. William W. Hogan, October 29, 2009 (Docket No. EL09-68).

[240] Testimony of Robert Weishaar, Jr., Attorney for Demand Response Supporters, Sept. 13, 2010 Tr. at 46-47, "Administratively constructing an LMP-based break point for compensating

the LMP payment by promising a "win-win" outcome, is nothing more than a fig leaf that provides little protection against the long-term potential for unintended market damage. As recognized by ISO-NE, generation is not dispatched and paid for only when such generation reduces LMP, instead generation is dispatched and paid for only when it is cost-effective.[241] Likewise, logic would require that demand resources be treated similar to generation resources and be similarly cost-effective.

During a technical conference convened to discuss the specific question on the necessity of a net benefits test, the Commission heard testimony from a panel of experts. A clear majority of the witnesses (representing a spectrum of interests that included demand response advocates, economists, generators, and the RTOs and ISOs) argued against the use of a complicated and admittedly imprecise[242] net benefits test.[243] Chief among their concerns was that a net benefits test is unnecessary since the market clearing function in a wholesale market, by definition, serves

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Demand Response participation would ignore many other qualitative and quantitative benefits of Demand Response. Focusing only on the LMP impacts of Demand Response is problematic."

[241] ISO-NE May 13, 2010 Comments at 3-4.

[242] Rule at P 80. Recognizing that "the threshold price approach we adopt here may result in instances both when demand response is not paid the LMP but would be cost-effective and when demand response is paid the LMP but is not cost-effective."

[243] Testimony of Donald Sipe, Attorney for Consumer Demand Response Initiative, Sept. 13, 2010 Tr. at 43, "[T]here is probably not a need for a Net Benefits Test. But if one is adopted, it should not be an artificial threshold that can be wrong both ways. It should not be a mechanism that treats DR differently than generation."

to guarantee that the resource that clears the market is the lowest-cost resource.[244] Other experts commented that the net benefits test would be complicated, costly to implement, and of little value.[245] Notably, Dr. Alfred E. Kahn, the majority's oft-quoted expert in defense of the full LMP payment, did not opine on the merit of subjecting the LMP payment to a net benefits test.

Further, as explained by Dr. Roy J. Shanker, if the Commission adopted the payment of LMP minus the retail rate ("G"), then there is no need for a net benefits test since the customer is paid the difference between the LMP and what they would have paid under their retail rate, which is their net benefit.[246] He testified that the "Net Benefits criteria is troubling in and of itself, as it explicitly incorporates consideration of portfolio effects caused by the reduced demand on all load payments, versus the economic decision-making of individual market participants pursuing their own legitimate business purpose."[247]

I similarly agree that this test is unnecessary and will only distort price signals by attracting more

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[244] Viridity Energy, Inc., Oct. 13, 2010 Comments at 10. *See also* ELCON Oct. 13, 2010 Comments at 3; and Environmental Defense Fund Comments at 2.

[245] Testimony of Andy Ott, Sr. Vice President, PJM Interconnection, Sept. 13, 2010 Tr. at 19, "[Y]ou have to use caution to actually take a benefits test and apply that to compensation, because you may have unintended consequences."

[246] Testimony of Roy J. Shanker, Ph.D, PJM Power Providers Group, Sept. 13, 2010 Tr. at 60, "If the Commission adopts the appropriate non-discriminatory pricing for Demand Response, and payment of LMP minus the retail rate in the context of customer that face a fixed retail rate, then there is no need for a Net Benefits test."

[247] *Id.*, Tr. at 61.

demand response than is economically efficient.[248] The use of a net benefits test also is troubling in that the Commission's decision can be viewed as somehow equating the concept of a just and reasonable rate with a lower price.[249] However, I recognize that to defend its compensation scheme, the majority needed some proposal that could arguably demonstrate that the cost of paying full LMP to demand resources would be outweighed by the "benefit" of a lower market price.[250] The net benefits test serves this unenviable role.

Relationship to State Retail Regulation

The Rule recognizes that the demand resource will retain the retail rate ("G") as part of the provider's total compensation, but declines to account for this savings citing "practical difficulties" for state commissions, RTOs and ISOs.[251] While the authority over

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[248] EPSA May 13, 2010 Comments at 23. *See also* May 13, 2010 Comments of APPA at 13; FTC at 9; Midwest TDUs at 14; Mirant at 2; New York Commission at 5; PJM at 6; PSEG at 5; and Potomac Economics at 6-8.

[249] Courts have stated that to be "just and reasonable," rates must fall within a "zone of reasonableness" where they are neither "less than compensatory" to producers nor "excessive" to consumers. *Farmers Union Central Exchange v. FERC*, 734 F.2d 1486 (D.C. Cir. 1984), cert denied, 469 U.S. 1034 (1984). *See also* EPSA May 13, 2010 Comments at 19; and ISO-NE at 26-28.

[250] Testimony of Ohio Commissioner Paul Centolella, Sept. 13, 2010 Tr. at 141, "The Net Benefits test reflects a recognition that paying full LMP may over-compensate Demand Response and increase cost to customers."

[251] Rule at P 63. The RTOs and ISOs uniformly state that compensation which ignores the retail rate will yield uneconomic outcomes and overcompensate the demand resource. Moreover, none of the RTOs or ISOs claimed it would be difficult to subtract the retail rate from the LMP payment. *See* May 13, 2010

retail rates is properly within the jurisdiction of the state commissions, under the LMP-G equation, the RTO/ISO merely subtracts the retail rate; it does not interfere with the retail rate in any way.[252] Although the Rule refers to the New York Commission's position that subtracting the retail rate would be an "administrative burden" or create "undue confusion",[253] other state commissions disagree and contend that the retail rate can be deducted without any concern about impacting the states' retail jurisdiction.[254]

Comments of CAISO at 5-6; ISO-NE at 17-26; Midwest ISO at 6-11; NYISO at 12-16; and PJM at 5-16.

[252] Testimony of Joel Newton, New England Power Generators Ass'n, Sept. 13, 2010 Tr. at 75; "The Commission is getting into a real close area with retail ratemaking as we go through this entire process. For the Commission then to say 'ignore the LSE payment' which is the realm of state commissions, it's almost as you're just hoping that the state commissions will go out and fix it. The state commissions can do that. . . .[b]ut the proper thing to do now is to get the price right at the outset." *See also* Testimony of Ohio Commissioner Paul Centolella, Sept. 13, 2010 Tr. at 197; "[FERC is] putting the state in the position where if we were to try to get back to an efficient level of incentives, we would be having to in effect issue a charge for energy that was not consumed. We would be doing what would be perceived as a take-back by that customer. And that would put us in a very difficult position."

[253] Rule at P 28. Significantly, the New York Commission "acknowledges the overstated price signal inherent in an LMP-based formula for DR compensation . . . ." "Although we understand that *an LMP demand response compensation formula may result in uneconomic demand response decisions in the markets (i.e., a price signal that exceeds marginal cost)*, it also creates an incentive to participate in DR programs. . . ." New York Commission May 13, 2010 Comments at 5-6 (emphasis added).

[254] Illinois Commission May 13, 2010 Comments at 13, "[I]f tariffs are well designed, controversy over the jurisdictional issue can be avoided. Requiring an ex ante approval of the retail rate

Moreover, the Rule does not conclude that LMP-G would interfere with the retail jurisdiction of the states, but goes as far as to acknowledge the subtraction of G is "perhaps feasible."[255] The fact is that this calculation is quite feasible. Markets such as the PJM Interconnection currently subtract the retail rate portion from the LMP payment and there is no evidence that accounting for the retail rate by making the necessary reduction is either burdensome or interferes with the retail jurisdiction of state commissions.[256]

The Unintended Consequences of Paying Too Much

Today's determination, unencumbered by "textbook economic analysis of the markets subject to our jurisdiction" will undoubtedly have effects, both in the short-term and the long-term.[257] The intended consequence of providing additional compensation to demand resources is that demand response participation will increase in the energy markets. In turn, this additional demand response participation will have the effect of lowering the market price. However,

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to be subtracted from the LMP at the time demand response resources are utilized . . . accomplishes this design." *See also* Indiana Commission September 16, 2009 Comments at 3 (Docket No. EL09-68), "LMP-G is an accepted indicator of cost-effectiveness. Therefore, to provide incentive compensation at a level that is above the LMP raises the specter of unjust and unreasonable rates."

[255] Rule at P 63.

[256] *See* Sections 3.3A.4 and 3.3A.5 (Market Settlements in the Real-Time and Day-Ahead Energy Markets) of the Appendix to Attachment K of the PJM Tariff.

[257] Rule at P 46.

it is at this point where the unintended effects will begin to appear.

With a reduced LMP, the price signal sent to customers will be that the cost of power is cheaper so they may decide to use more power even though the real cost of producing that power is now higher. Such a result turns the concept of scarcity pricing on its head and results in an economically inefficient outcome. Conversely, customers who are demand response providers now stand to receive more than the market price as an incentive to curtail their consumption and will begin to make inefficient decisions about using power. [258] Such inefficiencies will result in customers experiencing a short-term benefit by way of a lower LMP, but will also impose long-term costs on the energy markets.[259]

The long-term costs of allowing demand resources to receive preferential compensation will manifest

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[258] Federal Trade Commission May 13, 2010 Comments at 6, "If customers have to pay the retail price for power they use but pay nothing for power they resell, then they will have incentives to resell power in situations in which it would be more beneficial for society for them to consume it." *See also* EPSA May 13, 2010 Comments at 23; APPA at 13; FTC at 9; Midwest TDUs at 14; Mirant at 2; New York Commission at 5; PJM at 6; PSEG at 5; and Potomac Economics at 6-8.

[259] PJM's Independent Market Monitor (a/k/a Monitoring Analytics, LLC) Oct. 16, 2009 Comments at 7-8 (Docket No. EL09-68), "Demand side resources are not generation. In a well functioning market, demand-side resources avoid paying the market price of energy when they choose not to consume. This allows customers to make efficient decisions about using power. It also follows that a customer receiving more than the market price as an incentive to curtail will make inefficient decisions about using power, and that this inefficiency imposes a cost rather than providing a benefit to society."

themselves in various ways. As noted in my initial statement in this proceeding, the lack of dynamic prices at the retail level is the primary barrier to demand response participation. This Rule does not remedy this barrier and customers who pay fixed retail rates will not benefit from lower wholesale market prices. Meanwhile, at the wholesale level, the corrosive effect of overcompensating demand resources over time will come at the expense of other resources, particularly generation resources that will have less to invest in maintaining existing facilities and financing new facilities.[260]

The Commission's recent progress in promoting competitive wholesale energy markets has the potential to be undone as a result of this well-meaning, but misguided Rule. I believe in the proven value of market solutions and therefore agree with the majority's statement that "while the level of compensation provided to each resource affects its willingness and ability to participate in the market, ultimately the markets themselves will determine the level of generation and demand response resources needed for purposes of balancing the electricity grid."[261] That's precisely how markets should work. Price signals will attract resources and new

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[260] NYISO May 13, 2010 Comments at 15, "[P]aying demand response an LMP-based payment because it is thought that demand response participation will reduce LMPs for all customers is not a sufficient rationale for justifying an 'additional payment' for a favored technology. Demand response is not the only resource able to provide such benefits. However, [other] technologies may be kept out of the market by demand response that would be uneconomic at LMP-G but participates when subsidized at LMP."

[261] Rule at P 59.

investment when prices are high, and perhaps not so much when prices are low.[262] If the playing field is level, resources can compete to the best of their abilities and efficient, cost-effective market outcomes will result.

As noted earlier, I would have preferred that we allow the regional markets to continue to develop their own compensation proposals. However, I also recognize that returning to a pre-NOPR era would be difficult now that the Commission has signaled a new policy of standardized compensation. Accordingly, if I were to now support any standardization of demand response compensation, it would be the LMP-G approach, which in my opinion, is the only economically efficient outcome for the markets.

Ultimately, the Rule, by requiring demand resources to artificially suppress the market price in order to receive incomparable compensation, will negatively impact the long-term competitiveness of the organized wholesale energy markets.[263] As such,

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[262] PJM Interconnection's experience with paying LMP-G for demand response in its energy market provides an example of how market fundamentals properly influence demand resource participation. PJM's Independent Market Monitor recently reported that "[p]articipation levels through calendar year 2009 and through the first three months of 2010 were generally lower compared to prior years due to a number of factors, including lower price levels, lower load levels, and improved measurement and verification, but *have showed strong growth through the summer period as price levels and load levels have increased*. Citing Monitoring Analytics, LLC, *2010 State of the Market Report for PJM* at 30 (March 10, 2011) (emphasis added).

[263] Federal Power Act § 205(a), 16 U.S.C. § 824d (2006), "[A]ll rules and regulations affecting or pertaining to such rates or charges shall be just and reasonable, and any such rate or charge that is not just and reasonable is hereby declared to be unlawful."

lacking sufficient rationale, I cannot support this Rule as it violates the Commission's statutory mandate to ensure supplies of electric energy at just, reasonable, and not unduly discriminatory or preferential rates.

Philip D. Moeller
Commissioner

APPENDIX D

UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 11-1486

ELECTRIC POWER SUPPLY ASSOCIATION,
Petitioner

v.

FEDERAL ENERGY REGULATORY COMMISSION,
Respondent.

MADISON GAS AND ELECTRIC COMPANY, *et al*.,
Intervenors.

September Term, 2014

FERC-RM10-17-000
FERC-RM10-17-001

Filed On: September 17, 2014

Consolidated with 11-1489, 12-1088,
12-1091, 12-1093

BEFORE: Garland, *Chief Judge*, and Henderson,* Rogers, Tatel, Brown, Griffith, Kavanaugh, Srinivasan, Millett,* Pillard, and Wilkins, *Circuit Judges*

ORDER

Respondent's petition for rehearing en banc, the response thereto, and the brief of amici curiae in support of respondent were circulated to the full court, and a vote was requested. Thereafter, a majority of the judges eligible to participate did not vote in favor of the petition. Upon consideration of the foregoing, it is

ORDERED that the petition be denied.

Per Curiam

FOR THE COURT:
Mark J. Langer, Clerk

BY: /s/
Michael C. McGrail
Deputy Clerk

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* Circuit Judges Henderson and Millett did not participate in this matter.

APPENDIX E

UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 11-1486

ELECTRIC POWER SUPPLY ASSOCIATION,

Petitioner,

v.

FEDERAL ENERGY REGULATORY COMMISSION,

Respondent.

MADISON GAS AND ELECTRIC COMPANY, ET AL.,

Intervenors.

September Term, 2014

FERC-RM10-17-000
FERC-RM10-17-001

Filed On: December 15, 2014

Consolidated with 11-1489, 12-1088, 12-1091, 12-1093

BEFORE: Brown, *Circuit Judge*; and Edwards and Silberman, *Senior Circuit Judges*

ORDER

Upon consideration of the government's motion to extend stay of the mandate pending filing and disposition of petition for a writ of certiorari and the response thereto, it is

ORDERED that the motion be granted. The Clerk is directed to withhold issuance of the mandate through January 15, 2015. If within the period of stay, respondent notifies the Clerk in writing that a petition for writ of certiorari has been filed, the Clerk is directed to withhold issuance of the mandate pending the Supreme Court's final disposition. *See* Fed. R. App. P. 41(d)(2)(B); D.C. Cir. Rule 41(a)(2).

Per Curiam

FOR THE COURT:

Mark J. Langer, Clerk

BY: /s/ Jennifer M. Clark

Jennifer M. Clark
Deputy Clerk

APPENDIX F

UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 11-1486

ELECTRIC POWER SUPPLY ASSOCIATION,

Petitioner

v.

FEDERAL ENERGY REGULATORY COMMISSION,

Respondent.

MADISON GAS AND ELECTRIC COMPANY, *et al*.,

Intervenors.

September Term, 2014

FERC-RM10-17-000
FERC-RM10-17-001

Filed On: October 20, 2014

Consolidated with 11-1489, 12-1088,
12-1091, 12-1093

BEFORE: Brown, *Circuit Judge*, and Edwards* and Silberman, *Senior Circuit Judges*

ORDER

Upon consideration of the motion of the Federal Energy Regulatory Commission to stay issuance of mandate, the motion of intervenors for respondent to stay issuance of mandate, and the response to the motions, it is

ORDERED that the intervenors' motion be denied. It is

FURTHER ORDERED that FERC's motion to stay issuance of mandate be granted. The Clerk is directed to withhold the mandate through December 16, 2014. If, within the period of the stay, respondent notifies the Clerk in writing that a petition for writ of certiorari has been filed, the Clerk is directed to withhold issuance of the mandate pending the Supreme Court's final disposition. *See* Fed. R. App. P. 41(d)(2)(B); D.C. Cir. Rule 41(a)(2).

Per Curiam

FOR THE COURT:
Mark J. Langer, Clerk

BY: /s/
Jennifer M. Clark
Deputy Clerk

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* Senior Circuit Judge Edwards would grant intervenors' motion.

APPENDIX G

FEDERAL STATUTES

16 U.S.C.A. § 824. Declaration of policy; application of subchapter

(a) Federal regulation of transmission and sale of electric energy

It is declared that the business of transmitting and selling electric energy for ultimate distribution to the public is affected with a public interest, and that Federal regulation of matters relating to generation to the extent provided in this subchapter and subchapter III of this chapter and of that part of such business which consists of the transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce is necessary in the public interest, such Federal regulation, however, to extend only to those matters which are not subject to regulation by the States.

(b) Use or sale of electric energy in interstate commerce

(1) The provisions of this subchapter shall apply to the transmission of electric energy in interstate commerce and to the sale of electric energy at wholesale in interstate commerce, but except as provided in paragraph (2) shall not apply to any other sale of electric energy or deprive a State or State commission of its lawful authority now exercised over the exportation of hydroelectric energy which is transmitted across a State line. The Commission shall have jurisdiction over all facilities for such transmission or sale of electric energy, but shall not have jurisdiction, except as specifically provided in this subchapter and subchapter III of this chapter,

over facilities used for the generation of electric energy or over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter.

(2) Notwithstanding subsection (f) of this section, the provisions of sections 824b(a)(2), 824e(e), 824i, 824j, 824j-1, 824k, 824*o*, 824p, 824q, 824r, 824s, 824t, 824u, and 824v of this title shall apply to the entities described in such provisions, and such entities shall be subject to the jurisdiction of the Commission for purposes of carrying out such provisions and for purposes of applying the enforcement authorities of this chapter with respect to such provisions. Compliance with any order or rule of the Commission under the provisions of section 824b(a)(2), 824e(e), 824i, 824j, 824j-1, 824k, 824*o*, 824p, 824q, 824r, 824s, 824t, 824u, or 824v of this title, shall not make an electric utility or other entity subject to the jurisdiction of the Commission for any purposes other than the purposes specified in the preceding sentence.

(c) Electric energy in interstate commerce

For the purpose of this subchapter, electric energy shall be held to be transmitted in interstate commerce if transmitted from a State and consumed at any point outside thereof; but only insofar as such transmission takes place within the United States.

(d) "Sale of electric energy at wholesale" defined

The term "sale of electric energy at wholesale" when used in this subchapter, means a sale of electric energy to any person for resale.

(e) "Public utility" defined

The term "public utility" when used in this subchapter and subchapter III of this chapter means any person who owns or operates facilities subject to the jurisdiction of the Commission under this subchapter (other than facilities subject to such jurisdiction solely by reason of section 824e(e), 824e(f)[1], 824i, 824j, 824j-1, 824k, 824*o*, 824p, 824q, 824r, 824s, 824t, 824u, or 824v of this title).

(f) United States, State, political subdivision of a State, or agency or instrumentality thereof exempt

No provision in this subchapter shall apply to, or be deemed to include, the United States, a State or any political subdivision of a State, an electric cooperative that receives financing under the Rural Electrification Act of 1936 (7 U.S.C. 901 et seq.) or that sells less than 4,000,000 megawatt hours of electricity per year, or any agency, authority, or instrumentality of any one or more of the foregoing, or any corporation which is wholly owned, directly or indirectly, by any one or more of the foregoing, or any officer, agent, or employee of any of the foregoing acting as such in the course of his official duty, unless such provision makes specific reference thereto.

(g) Books and records

(1) Upon written order of a State commission, a State commission may examine the books, accounts, memoranda, contracts, and records of—

(A) an electric utility company subject to its regulatory authority under State law,

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[1] So in original. Section 824e of this title does not contain a subsec. (f).

(B) any exempt wholesale generator selling energy at wholesale to such electric utility, and

(C) any electric utility company, or holding company thereof, which is an associate company or affiliate of an exempt wholesale generator which sells electric energy to an electric utility company referred to in subparagraph (A),

wherever located, if such examination is required for the effective discharge of the State commission's regulatory responsibilities affecting the provision of electric service.

(2) Where a State commission issues an order pursuant to paragraph (1), the State commission shall not publicly disclose trade secrets or sensitive commercial information.

(3) Any United States district court located in the State in which the State commission referred to in paragraph (1) is located shall have jurisdiction to enforce compliance with this subsection.

(4) Nothing in this section shall—

(A) preempt applicable State law concerning the provision of records and other information; or

(B) in any way limit rights to obtain records and other information under Federal law, contracts, or otherwise.

(5) As used in this subsection the terms "affiliate", "associate company", "electric utility company", "holding company", "subsidiary company", and "exempt wholesale generator" shall have the same meaning as when used in the Public Utility Holding Company Act of 2005 [42 U.S.C.A. § 16451 et seq.].

16 U.S.C.A. § 824d. Rates and charges; schedules; suspension of new rates; automatic adjustment clauses

(a) Just and reasonable rates

All rates and charges made, demanded, or received by any public utility for or in connection with the transmission or sale of electric energy subject to the jurisdiction of the Commission, and all rules and regulations affecting or pertaining to such rates or charges shall be just and reasonable, and any such rate or charge that is not just and reasonable is hereby declared to be unlawful.

(b) Preference or advantage unlawful

No public utility shall, with respect to any transmission or sale subject to the jurisdiction of the Commission, (1) make or grant any undue preference or advantage to any person or subject any person to any undue prejudice or disadvantage, or (2) maintain any unreasonable difference in rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service.

(c) Schedules

Under such rules and regulations as the Commission may prescribe, every public utility shall file with the Commission, within such time and in such form as the Commission may designate, and shall keep open in convenient form and place for public inspection schedules showing all rates and charges for any transmission or sale subject to the jurisdiction of the Commission, and the classifications, practices, and regulations affecting such rates and charges, together with all contracts which in any manner affect or relate to such rates, charges, classifications, and services.

(d) Notice required for rate changes

Unless the Commission otherwise orders, no change shall be made by any public utility in any such rate, charge, classification, or service, or in any rule, regulation, or contract relating thereto, except after sixty days' notice to the Commission and to the public. Such notice shall be given by filing with the Commission and keeping open for public inspection new schedules stating plainly the change or changes to be made in the schedule or schedules then in force and the time when the change or changes will go into effect. The Commission, for good cause shown, may allow changes to take effect without requiring the sixty days' notice herein provided for by an order specifying the changes so to be made and the time when they shall take effect and the manner in which they shall be filed and published.

(e) Suspension of new rates; hearings; five-month period

Whenever any such new schedule is filed the Commission shall have authority, either upon complaint or upon its own initiative without complaint, at once, and, if it so orders, without answer or formal pleading by the public utility, but upon reasonable notice, to enter upon a hearing concerning the lawfulness of such rate, charge, classification, or service; and, pending such hearing and the decision thereon, the Commission, upon filing with such schedules and delivering to the public utility affected thereby a statement in writing of its reasons for such suspension, may suspend the operation of such schedule and defer the use of such rate, charge, classification, or service, but not for a longer period than five months beyond the time when it would otherwise go into effect; and after full hearings, either completed before or after the rate, charge, classification, or service goes into effect, the Commission may make such orders with reference thereto as would be proper in a proceeding initiated after it had become effective. If the proceeding has not been concluded and an order made at the expiration of such five months, the proposed change of rate, charge, classification, or service shall go into effect at the end of such period, but in case of a proposed increased rate or charge, the Commission may by order require the interested public utility or public utilities to keep accurate account in detail of all amounts received by reason of such increase, specifying by whom and in whose behalf such amounts are paid, and upon completion of the hearing and decision may by further order require such public utility or public utilities to refund, with interest, to the persons in whose behalf such amounts were paid, such portion of such increased rates or charges as by its decision shall be found not justified. At any hearing involving a rate or charge sought to be increased, the burden of proof to show that the increased rate or charge is just and reasonable shall be upon the public utility, and the Commission shall give to the hearing and decision of such questions preference over other questions pending before it and decide the same as speedily as possible.

(f) Review of automatic adjustment clauses and public utility practices; action by Commission; "automatic adjustment clause" defined

(1) Not later than 2 years after November 9, 1978, and not less often than every 4 years thereafter, the Commission shall make a thorough review of automatic adjustment clauses in public utility rate schedules to examine—

(A) whether or not each such clause effectively provides incentives for efficient use of resources (including economical purchase and use of fuel and electric energy), and

(B) whether any such clause reflects any costs other than costs which are—

(i) subject to periodic fluctuations and

(ii) not susceptible to precise determinations in rate cases prior to the time such costs are incurred.

Such review may take place in individual rate proceedings or in generic or other separate proceedings applicable to one or more utilities.

(2) Not less frequently than every 2 years, in rate proceedings or in generic or other separate proceedings, the Commission shall review, with respect to each public utility, practices under any automatic adjustment clauses of such utility to insure efficient use of resources (including economical purchase and use of fuel and electric energy) under such clauses.

(3) The Commission may, on its own motion or upon complaint, after an opportunity for an evidentiary hearing, order a public utility to—

(A) modify the terms and provisions of any automatic adjustment clause, or

(B) cease any practice in connection with the clause,

if such clause or practice does not result in the economical purchase and use of fuel, electric energy, or other items, the cost of which is included in any rate schedule under an automatic adjustment clause.

(4) As used in this subsection, the term "automatic adjustment clause" means a provision of a rate schedule which provides for increases or decreases (or both), without prior hearing, in rates reflecting increases or decreases (or both) in costs incurred by an electric utility. Such term does not include any rate which takes effect subject to refund and subject to a later determination of the appropriate amount of such rate.

16 U.S.C.A. § 824e. Power of Commission to fix rates and charges; determination of cost of production or transmission

(a) Unjust or preferential rates, etc.; statement of reasons for changes; hearing; specification of issues

Whenever the Commission, after a hearing held upon its own motion or upon complaint, shall find that any rate, charge, or classification, demanded, observed, charged, or collected by any public utility for any transmission or sale subject to the jurisdiction of the Commission, or that any rule, regulation, practice, or contract affecting such rate, charge, or classification is unjust, unreasonable, unduly discriminatory or preferential, the Commission shall determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force, and shall fix the same by order. Any complaint or motion of the Commission to initiate a proceeding under this section shall state the change or changes to be made in the rate, charge, classification, rule, regulation, practice, or contract then in force, and the reasons for any proposed change or changes therein. If, after review of any motion or complaint and answer, the Commission shall decide to hold a hearing, it shall fix by order the time and place of such hearing and shall specify the issues to be adjudicated.

(b) Refund effective date; preferential proceedings; statement of reasons for delay; burden of proof; scope of refund order; refund orders in cases of dilatory behavior; interest

Whenever the Commission institutes a proceeding under this section, the Commission shall establish a refund effective date. In the case of a proceeding instituted on complaint, the refund effective date shall not be earlier than the date of the filing of such complaint nor later than 5 months after the filing of such complaint. In the case of a proceeding instituted by the Commission on its own motion, the refund effective date shall not be earlier than the date of the publication by the Commission of notice of its intention to initiate such proceeding nor later than 5 months after the publication date. Upon institution of a proceeding under this section, the Commission shall give to the decision of such proceeding the same preference as provided under section 824d of this title and otherwise act as speedily as possible. If no final decision is rendered by the conclusion of the 180-day period commencing upon initiation of a proceeding pursuant to this section, the Commission shall state the reasons why it has failed to do so and shall state its best estimate as to when it reasonably expects to make such decision. In any proceeding under this section, the burden of proof to show that any rate, charge, classification, rule, regulation, practice, or contract is unjust, unreasonable, unduly discriminatory, or preferential shall be upon the Commission or the complainant. At the conclusion of any proceeding under this section, the Commission may order refunds of any amounts paid, for the period subsequent to the refund effective date through a date fifteen months after such refund effective date, in excess of those which would have been paid under the just and reasonable rate, charge, classification, rule, regulation, practice, or contract which the Commission orders to be thereafter observed and in force: *Provided,* That if the proceeding is not concluded within fifteen months after the refund effective date and if the Commission determines at the conclusion of the proceeding that the proceeding was not resolved within the fifteen-month period primarily because of dilatory behavior by the public utility, the Commission may order refunds of any or all amounts paid for the period subsequent to the refund effective date and prior to the conclusion of the proceeding. The refunds shall be made, with interest, to those persons who have paid those rates or charges which are the subject of the proceeding.

(c) Refund considerations; shifting costs; reduction in revenues; "electric utility companies" and "registered holding company" defined

Notwithstanding subsection (b) of this section, in a proceeding commenced under this section involving two or more electric utility companies of a registered holding company, refunds which might otherwise be payable under subsection (b) of this section shall not be ordered to the extent that such refunds would result from any portion of a Commission order that (1) requires a decrease in system production or transmission costs to be paid by one or more of such electric companies; and (2) is based upon a determination that the amount of such decrease should be paid through an increase in the costs to be paid by other electric utility companies of such registered holding company: *Provided,* That refunds, in whole or in part, may be ordered by the Commission if it determines that the registered holding company would not experience any reduction in revenues which results from an inability of an electric utility company of the holding company to recover such increase in costs for the period between the refund effective date and the effective date of the Commission's order. For purposes of this subsection, the terms "electric utility companies" and "registered holding company" shall have the same meanings as provided in the Public Utility Holding Company Act of 1935, as amended [15 U.S.C.A. § 79 et seq.].

(d) Investigation of costs

The Commission upon its own motion, or upon the request of any State commission whenever it can do so without prejudice to the efficient and proper conduct of its affairs, may investigate and determine the cost of the production or transmission of electric energy by means of facilities under the jurisdiction of the Commission in cases where the Commission has no authority to establish a rate governing the sale of such energy.

(e) Short-term sales

(1) In this subsection:

(A) The term "short-term sale" means an agreement for the sale of electric energy at wholesale in interstate commerce that is for a period of 31 days or less (excluding monthly contracts subject to automatic renewal).

(B) The term "applicable Commission rule" means a Commission rule applicable to sales at wholesale by public utilities that the Commission determines after notice and comment should also be applicable to entities subject to this subsection.

(2) If an entity described in section 824(f) of this title voluntarily makes a short-term sale of electric energy through an organized market in which the rates for the sale are established by Commission-approved tariff (rather than by contract) and the sale violates the terms of the tariff or applicable Commission rules in effect at the time of the sale, the entity shall be subject to the refund authority of the Commission under this section with respect to the violation.

(3) This section shall not apply to—

(A) any entity that sells in total (including affiliates of the entity) less than 8,000,000 megawatt hours of electricity per year; or

(B) an electric cooperative.

(4)(A) The Commission shall have refund authority under paragraph (2) with respect to a voluntary short term sale of electric energy by the Bonneville Power Administration only if the sale is at an unjust and unreasonable rate.

(B) The Commission may order a refund under subparagraph (A) only for short-term sales made by the Bonneville Power Administration at rates that are higher than the highest just and reasonable rate charged by any other entity for a short-term sale of electric energy in the same geographic market for the same, or most nearly comparable, period as the sale by the Bonneville Power Administration.

(C) In the case of any Federal power marketing agency or the Tennessee Valley Authority, the Commission shall not assert or exercise any regulatory authority or power under paragraph (2) other than the ordering of refunds to achieve a just and reasonable rate.

Energy Policy Act of 2005, Pub. L. No. 109-58, § 1252(f)

(f) FEDERAL ENCOURAGEMENT OF DEMAND RESPONSE DEVICES.—It is the policy of the United States that time-based pricing and other forms of demand response, whereby electricity customers are provided with electricity price signals and the ability to benefit by responding to them, shall be encouraged, the deployment of such technology and devices that enable electricity customers to participate in such pricing and demand response systems shall be facilitated, and unnecessary barriers to demand response participation in energy, capacity and ancillary service markets shall be eliminated. It is further the policy of the United States that the benefits of such demand response that accrue to those not deploying such technology and devices, but who are part of the same regional electricity entity, shall be recognized.

APPENDIX H

FEDERAL REGULATION

18 C.F.R. § 35.28. Non-discriminatory open access transmission tariff.

(a) Applicability. This section applies to any public utility that owns, controls or operates facilities used for the transmission of electric energy in interstate commerce and to any non-public utility that seeks voluntary compliance with jurisdictional transmission tariff reciprocity conditions.

(b) Definitions—

(1) Requirements service agreement means a contract or rate schedule under which a public utility provides any portion of a customer's bundled wholesale power requirements.

(2) Economy energy coordination agreement means a contract, or service schedule thereunder, that provides for trading of electric energy on an "if, as and when available" basis, but does not require either the seller or the buyer to engage in a particular transaction.

(3) Non-economy energy coordination agreement means any non-requirements service agreement, except an economy energy coordination agreement as defined in paragraph (b)(2) of this section.

(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.

(c) Non-discriminatory open access transmission tariffs.

(1) Every public utility that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce must have on file with the Commission an open access transmission tariff of general applicability for transmission services, including ancillary services, over such facilities. Such tariff must be the pro forma tariff promulgated by the Commission, as amended from time to time, or such other tariff as may be approved by the Commission consistent with the principles set forth in Commission rulemaking proceedings promulgating and amending the pro forma tariff.

(i) Subject to the exceptions in paragraphs (c)(1)(ii), (c)(1)(iii), (c)(1)(iv), and (c)(1)(v) of this section, the open access transmission tariff, which tariff must be the pro forma tariff required by Commission rulemaking proceedings promulgating and amending the pro forma tariff, and accompanying rates must be filed no later than 60 days prior to the date on which a public utility would engage in a sale of electric energy at wholesale in interstate commerce or in the transmission of electric energy in interstate commerce.

(ii) If a public utility owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce, it must file the revisions to its open access transmission tariff required by Commission rulemaking proceedings promulgating and amending the pro forma tariff, pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA in accordance with the procedures set forth in Commission rulemaking proceedings promulgating and amending the pro forma tariff.

(iii) If a public utility owns, controls, or operates transmission facilities used for the transmission of electric energy in interstate commerce, such facilities are jointly owned with a non-public utility, and the joint ownership contract prohibits transmission service over the facilities to third parties, the public utility with respect to access over the public utility's share of the jointly owned facilities must file the revisions to its open access transmission tariff required by Commission rulemaking proceedings promulgating and amending the pro forma tariff pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA in accordance with the procedures set forth in Commission rulemaking proceedings promulgating and amending the pro forma tariff.

(iv) Any public utility whose transmission facilities are under the independent control of a Commission-approved ISO or RTO may satisfy its obligation under paragraph (c)(1) of this section, with respect to such facilities, through the open access transmission tariff filed by the ISO or RTO.

(v) If a public utility obtains a waiver of the tariff requirement pursuant to paragraph (d) of this section, it does not need to file the open access transmission tariff required by this section.

(vi) Any public utility that seeks a deviation from the pro forma tariff promulgated by the Commission, as amended from time to time, must demonstrate that the deviation is consistent with the principles set forth in Commission rulemaking proceedings promulgating and amending the pro forma tariff.

(vii) Each public utility's open access transmission tariff must include the standards incorporated by reference in part 38 of this chapter.

(2) Subject to the exceptions in paragraphs (c)(2)(i) and (c)(3)(iii) of this section, every public utility that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce, and that uses those facilities to engage in wholesale sales and/or purchases of electric energy, or unbundled retail sales of electric energy, must take transmission service for such sales and/or purchases under the open access transmission tariff filed pursuant to this section.

(i) For sales of electric energy pursuant to a requirements service agreement executed on or before July 9, 1996, this requirement will not apply unless separately ordered by the Commission. For sales of electric energy pursuant to a bilateral economy energy coordination agreement executed on or before July 9, 1996, this requirement is effective on December 31, 1996. For sales of electric energy pursuant to a bilateral non-economy energy coordination agreement executed on or before July 9, 1996, this requirement will not apply unless separately ordered by the Commission.

(ii) [Reserved]

(3) Every public utility that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce, and that is a member of a power pool, public utility holding company, or other multi-lateral trading arrangement or agreement that contains transmission rates, terms or conditions, must have on file a joint pool-wide or system-wide open access transmission tariff, which tariff must be the pro forma tariff promulgated by the Commission, as amended from time to time, or such other open access transmission tariff as may be approved by the Commission consistent with the principles set forth in Commission rulemaking proceedings promulgating and amending the pro forma tariff.

(i) For any power pool, public utility holding company or other multi-lateral arrangement or agreement that contains transmission rates, terms or conditions and that is executed after October 11, 2011, this requirement is effective on the date that transactions begin under the arrangement or agreement.

(ii) For any power pool, public utility holding company or other multi-lateral arrangement or agreement that contains transmission rates, terms or conditions and that is executed on or before May 14, 2007, a public utility member of such power pool, public utility holding company or other multi-lateral arrangement or agreement that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce must file the revisions to its joint pool-wide or system-wide open access transmission tariff required by Commission rule-making proceedings promulgating and amending the pro forma tariff pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA in accordance with the procedures set forth in Commission rulemaking proceedings promulgating and amending the pro forma tariff.

(iii) A public utility member of a power pool, public utility holding company or other multi-lateral arrangement or agreement that contains transmission rates, terms or conditions and that is executed on or before July 9, 1996 must take transmission service under a joint pool-wide or system-wide open access transmission tariff filed pursuant to this section for wholesale trades among the pool or system members.

(4) Consistent with paragraph (c)(1) of this section, every Commission-approved ISO or RTO must have on file with the Commission an open access transmission tariff of general applicability for transmission services, including ancillary services, over such facilities. Such tariff must be the pro forma tariff promulgated by the Commission, as amended from time to time, or such other tariff as may be approved by the Commission consistent with the principles set forth in Commission rulemaking proceedings promulgating and amending the pro forma tariff.

(i) Subject to paragraph (c)(4)(ii) of this section, a Commission-approved ISO or RTO must file the revisions to its open access transmission tariff required by Commission rulemaking proceedings promulgating and amending the pro forma tariff pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA in accordance with the procedures set forth in Commission rulemaking proceedings promulgating and amending the pro forma tariff.

(ii) If a Commission-approved ISO or RTO can demonstrate that its existing open access transmission tariff is consistent with or superior to the pro forma tariff promulgated by the Commission, as amended from time to time, the Commission-approved ISO or RTO may instead set forth such demonstration in its filing pursuant to section 206 in accordance with the procedures set forth in Commission rulemaking proceedings promulgating and amending the pro forma tariff.

(d) Waivers. A public utility subject to the requirements of this section and Order No. 889, FERC Stats. & Regs. ¶ 31,037 (Final Rule on Open Access Same-Time Information System and Standards of Conduct) may file a request for waiver of all or part of the requirements of this section, or Part 37 (Open Access Same-Time Information System and Standards of Conduct for Public Utilities), for good cause shown. Except as provided in paragraph (f) of this section, an application for waiver must be filed no later than 60 days prior to the time the public utility would have to comply with the requirement.

(e) Non-public utility procedures for tariff reciprocity compliance.

(1) A non-public utility may submit an open access transmission tariff and a request for declaratory order that its voluntary transmission

tariff meets the requirements of Commission rulemaking proceedings promulgating and amending the pro forma tariff.

(i) Any submittal and request for declaratory order submitted by a non-public utility will be provided an NJ (non-jurisdictional) docket designation.

(ii) If the submittal is found to be an acceptable open access transmission tariff, an applicant in a Federal Power Act (FPA) section 211 or 211A proceeding against the non-public utility shall have the burden of proof to show why service under the open access transmission tariff is not sufficient and why a section 211 or 211A order should be granted.

(2) A non-public utility may file a request for waiver of all or part of the reciprocity conditions contained in a public utility open access transmission tariff, for good cause shown. An application for waiver may be filed at any time.

(f) Standard generator interconnection procedures and agreements.

(1) Every public utility that is required to have on file a non-discriminatory open access transmission tariff under this section must amend such tariff by adding the standard interconnection procedures and agreement and the standard small generator interconnection procedures and agreement required by Commission rulemaking proceedings promulgating and amending such interconnection procedures and agreements, or such other interconnection procedures and agreements as may be required by Commission rulemaking proceedings promulgating and amending

the standard interconnection procedures and agreement and the standard small generator interconnection procedures and agreement.

(i) Any public utility that seeks a deviation from the standard interconnection procedures and agreement or the standard small generator interconnection procedures and agreement required by Commission rulemaking proceedings promulgating and amending such interconnection procedures and agreements, must demonstrate that the deviation is consistent with the principles set forth in Commission rulemaking proceedings promulgating and amending such interconnection procedures and agreements.

(ii) to (iv) [Reserved by 77 FR 41541]

(2) The non-public utility procedures for tariff reciprocity compliance described in paragraph (e) of this section are applicable to the standard interconnection procedures and agreements.

(3) A public utility subject to the requirements of this paragraph (f) may file a request for waiver of all or part of the requirements of this paragraph (f), for good cause shown.

(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 accept bids from an aggregator of retail customers that aggregates the demand response of the customers of utilities that distributed more than 4 million megawatt-hours in the previous fiscal year, and the customers of utilities that distributed 4 million megawatt-hours or less in the previous fiscal year, where the relevant electric retail regulatory authority permits such customers' demand response to be bid into organized markets by an aggregator of retail customers. An independent system operator or regional transmission organization must not accept bids from an aggregator of retail customers that aggregates the demand response of the customers of utilities that distributed more than 4 million megawatt-hours in the previous fiscal year, where the relevant electric retail regulatory authority prohibits such customers' demand response to be bid into organized markets by an aggregator of retail customers, or the customers of utilities that distributed 4 million megawatt-hours or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such customers' demand response to be bid into organized markets by an aggregator of retail customers.

(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.

(v) Demand response compensation in energy markets. Each Commission-approved independent system operator or regional transmission organization that has a tariff provision permitting demand response resources to participate as a resource in the energy market by reducing consumption of electric energy from their expected levels in response to price signals must:

(A) Pay to those demand response resources the market price for energy for these reductions when these demand response resources have the capability to balance supply and demand and when payment of the market price for energy to these resources is cost-effective as determined by a net benefits test accepted by the Commission;

(B) Allocate the costs associated with demand response compensation proportionally to all entities that purchase from the relevant energy market in the area(s) where the demand response reduces the market price for energy at the time when the demand response resource is committed or dispatched.

(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) Electronic delivery of data. Each Commission-approved regional transmission organization and independent system operator must electronically deliver to the Commission, on an ongoing basis and in a form and manner consistent with its own collection of data and in a form and manner acceptable to the Commission, data related to the markets that the regional transmission organization or independent system operator administers.

(5) 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.

(6) 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.

(7) 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.

(8) Frequency regulation compensation in ancillary services markets. Each Commission-approved independent system operator or regional transmission organization that has a tariff that provides for the compensation for frequency regulation service must provide such compensation based on the actual service provided, including a capacity payment that includes the marginal unit's opportunity costs and a payment for performance that reflects the quantity of frequency regulation service provided by a resource when the resource is accurately following the dispatch signal.