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Assessment of

Demand Response and Advanced Metering

Staff Report

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FERC Staff Report

ASSESSMENT OF DEMAND RESPONSE AND ADVANCED METERING

Pursuant to Energy Policy Act of 2005 section 1252(e)(3)

September 2009

This report is the Commission staff's fourth annual report on demand response and advanced metering. It fulfills a requirement of the Energy Policy Act of 2005 (EPAcT 2005) section 1252(e)(3)¹ that the Federal Energy Regulatory Commission (FERC or Commission) prepare and publish an annual report, by appropriate region, that assesses electricity demand response resources, including those available from all consumer classes.²

This report draws heavily from a Commission staff report on demand response potential that was submitted to Congress in June 2009, as required by section 529(a) of the Energy Independence and Security Act of 2007.³ That report, *A National Assessment of Demand Response Potential* (referred to here as the Assessment)⁴ already covers many of the topics required for this annual report. As such, this 2009 FERC Demand Response Report provides a brief summary of the significant findings of the Assessment and provides information on regulatory activities and actions taken by the Commission and state policymakers over the last year. Next year's report, the 2010 FERC Demand Response Report, like the 2006 and 2008 reports, will present the results of another comprehensive nationwide survey on demand response and advanced metering.

Background and Significant Findings of the Assessment

¹ Energy Policy Act of 2005, Pub. L. No. 109-58, § 1252(e)(3), 119 Stat. 594 (2005) (EPAcT 2005 section 1252(e)(3)).

² The Commission submitted the first report, *Assessment of Demand Response and Advanced Metering*, in August 2006 (referred to here as the 2006 FERC Demand Response Report). FERC, *Assessment of Demand Response & Advanced Metering: Staff Report*, Docket No. AD06-2, August 2006, available at <http://www.ferc.gov/industries/electric/indus-act/demand-response.asp>. The Commission submitted the second report in September 2007, FERC, *Assessment of Demand Response & Advanced Metering: Staff Report*, September 2007, available at <http://www.ferc.gov/industries/electric/indus-act/demand-response.asp>, and the third report in December 2008, FERC, *Assessment of Demand Response & Advanced Metering: Staff Report*, December 2008, available at <http://www.ferc.gov/industries/electric/indus-act/demand-response.asp>. The Commission had submitted full reports based on extensive surveys in 2006 and 2008, and an abbreviated report in the intervening years.

³ Energy Independence and Security Act of 2007, Pub. L. No. 110-140, § 529, 121 Stat. 1492, 1664 (2007).

⁴ *A National Assessment of Demand Response Potential*, June 2009, available at <http://www.ferc.gov/legal/staff-reports/06-09-demand-response.pdf> (Assessment).

The Assessment estimates the potential for demand response, both nationally and for each state, through 2019 under the following four scenarios. The Business-as-Usual scenario is an estimate of demand response if current and planned demand response stays constant, and is intended to reflect the continuation of current programs and tariffs. The Expanded Business-as-Usual scenario assumes that the current mix of demand response programs are expanded to all states where they are cost-effective and achieve “best practices” levels of participation. It also assumes that there is a modest amount of demand response from retail pricing programs designed to encourage demand response together with advanced metering infrastructure (AMI) deployment. The Achievable Participation scenario assumes AMI is installed for all retail customers, a dynamic pricing tariff is the default tariff, and other programs are available to those customers who decide to opt out of dynamic pricing. The Full Participation scenario assumes that all customers have AMI and must take service under a dynamic pricing tariff that is offered with proven enabling technologies. The Assessment also makes recommendations for overcoming barriers to more use of demand response. What follows is a discussion of the Assessment in relation to the six requirements included in section 1252(e)(3) of EPAct 2005, which directs the Commission to identify and review:

- (A) saturation and penetration rate of advanced meters and communications technologies, devices and systems;
- (B) existing demand response programs and time-based rate programs;
- (C) the annual resource contribution of demand resources;
- (D) the potential for demand response as a quantifiable, reliable resource for regional planning purposes;
- (E) steps taken to ensure that, in regional transmission planning and operations, demand resources are provided equitable treatment as a quantifiable, reliable resource relative to the resource obligations of any load-serving entity, transmission provider, or transmitting party; and
- (F) regulatory barriers to improved customer participation in demand response, peak reduction and critical period pricing programs.

(A) Saturation and penetration rates of advanced meters

In the development of the demand response potential scenarios that rely on dynamic pricing, the Assessment estimates that there are 7.95 million installed advanced meters nationwide in 2009. This estimate was based on a review and analysis of existing information sources (which included the Commission’s 2008 survey) on current advanced metering deployment. The Assessment then estimates demand response potential at 5 and 10 years based on future AMI under two deployment scenarios. Under a partial deployment scenario (which is reflected in the Business-as-Usual and Expanded Business-as-Usual scenarios), about 80 million meters are installed by 2019, and about 141 million are installed by 2019 under a full deployment scenario (reflected in the Achievable and Full Participation scenarios).⁵ Neither scenario is intended as an accurate forecast of AMI deployment (such a forecast was outside the scope of the Assessment); however, the Assessment indicates that the partial deployment scenario is “probably closer to what might actually occur,”⁶ and is based on the expert judgment of the

⁵ *Id.* at 59 fig.24.

⁶ *Id.* at 59.

consultants to the Commission staff using data available from the Commission and the Energy Information Administration (EIA).⁷ Appendix D of the Assessment contains projections of the percent of meters in each state that will be AMI meters in 2019.⁸

(B) Existing demand response programs and time-based rate programs

The Assessment relies on certain information (e.g., the 2008 FERC Demand Response Survey, EIA state energy data, and utility/ISO load data) and assumptions about existing programs and sets out the types and sizes of existing demand response and time-based rate programs. The Assessment estimates the 2009 national reduction in peak demand from demand response in 2009 to be 37 gigawatts (GW), which is the reduction under the Business-as-Usual scenario.⁹

(C) Annual resource contribution of demand resources, and (D) potential for demand response as a quantifiable, reliable resource for regional planning purposes

The Assessment provides a comprehensive assessment of demand response potential, both nationally and for each state, through 2019. It estimates that the potential for peak electricity demand reductions across the country in 2019 is between 38 GW and 188 GW, up to 20 percent of national peak demand without any demand response, depending on how extensively demand response is applied – 38 GW in the Business-as-Usual Scenario, 82 GW for the Expanded Business-as-Usual Scenario, 138 GW for the Achievable Participation Scenario, and 188 GW for the Full Participation Scenario.¹⁰ The results under the four scenarios illustrate how the demand response potential increases under various assumptions, such as the number of customers participating and the use of “smart” electric appliances with dynamic electric rates that change with system conditions. Comparing the Full Participation scenario with the Business-as-Usual scenario, the report estimates that demand response programs could reduce the projected 2019 peak load by as much as 150 GW.¹¹

The Assessment also provides, for the first time, estimates of demand response potential for each of the 50 states and the District of Columbia.¹² It estimates the demand response potential for residential and other types of electric customers in each state and analyzes the effect of using technologies, such as programmable thermostats, to assist consumers achieve the estimated potential.¹³

⁷ *Id.* at 225–30.

⁸ *Id.* at 230 fig. D-5.

⁹ *Id.* at 27.

¹⁰ *Id.* at 27 fig. 1.

¹¹ *Id.* at x.

¹² *Id.* at app. A.

¹³ *Id.* at 31-32.

(E) Steps taken to ensure that, in regional transmission planning and operations, demand resources are provided equitable treatment as a quantifiable, reliable resource relative to the resource obligations of any load-serving entity, transmission provider, or transmitting party

In the year since the 2008 FERC Demand Response Report issued, the Commission, state governments, retail rate regulators, and individual utilities have taken the following additional steps to recognize the role of demand response in the reliable and efficient operation of wholesale markets and the transmission system.

FERC Identifies Smart Grid-Enabled Demand Response as Key Priority for Standards Development to Achieve Smart Grid Interoperability

On July 16, 2009, the Commission issued a Final Smart Grid Policy to guide and prioritize the development of smart grid devices and systems, and to adopt an Interim Rate Policy to encourage investment in smart grid technologies.¹⁴ The Commission stated that smart grid-enabled demand response is a key priority because of its potential to help address several bulk-power system challenges, including reliably integrating unprecedented amounts of variable generation resources into the electric grid.¹⁵ To further this goal, the final policy explains that a key priority should be development of standards to enhance interoperability and communications between system operators, demand response resources, and the systems that support them.¹⁶ Emphasis should be put on further development of use cases and scenarios for demand response, particularly with regard to dispatchable demand response and various forms of dynamic pricing.¹⁷ Further, the Commission encourages the National Institute of Standards and Technology and its industry collaborators to continue investigating potential national interoperability standards for advanced metering systems.¹⁸

FERC Acts to Ensure Comparable Treatment of Demand Resources

FERC recognized the important role that demand response can play in ensuring the competitiveness of the Regional Transmission Operator (RTO) and Independent System Operator (ISO) organized markets and the reliability of grid operations. As the Commission stated in Order No. 719, “[d]emand response can provide competitive pressure to reduce wholesale power prices; increases awareness of energy usage; provides for more efficient operation of markets; mitigates market power; enhances reliability; and in combination with certain new technologies, can support the use of renewable energy resources, distributed generation, and advanced metering.”¹⁹

¹⁴ *Smart Grid Policy*, 128 FERC ¶ 61,060, at P 10 (2009).

¹⁵ *Id.* at P 74.

¹⁶ *Id.* at P 63 (citing *Smart Grid Policy*, 126 FERC ¶ 61,253, at P 37-39 (2009)).

¹⁷ *Id.* at P 74-77.

¹⁸ *Id.* at P 76.

¹⁹ *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, 73 Fed. Reg. 64,100 (Oct. 28, 2008), FERC Stats. & Regs. ¶ 31,281, at P 16 (2008), *order on reh'g*, Order No. 719-A, 128 FERC ¶ 61,059 (2009) (requiring RTOs and ISOs to amend their market rules to (1) permit

Building on this finding, the Commission required RTOs and ISOs to take actions to ensure comparable treatment of demand response resources. For instance, the Commission required each RTO or ISO to accept bids from demand response resources if they are technically capable of providing the ancillary service, and submit a bid under the generally-applicable bidding rules at or below market-clearing price, unless the laws or regulations of the relevant electric retail regulatory authority do not permit retail customers to participate.²⁰ In addition, the Commission required RTOs and ISOs to assess and report to the Commission any remaining barriers to comparable treatment of demand response resources that are within the Commission's jurisdiction within six months of the rule's publication.²¹ As part of the report, the Commission ordered RTOs and ISOs to include any proposed solutions and a timeline for implementation.²²

Regional Transmission Planning Processes

In 2007, the Commission issued a final rule, Order No. 890, which addressed the transmission planning process of FERC-jurisdictional transmission providers.²³ Order No. 890 requires transmission providers to establish a coordinated, open and transparent transmission planning process that complies with certain principles,²⁴ and that allows for the incorporation of demand

aggregators of demand response to bid into organized electric markets, subject to certain conditions, and (2) reform market rules so that prices during operating reserve shortages more accurately reflect the value of energy during such shortages). On rehearing, the Commission broadly affirmed its finding that aggregators of demand response should be permitted to bid demand response directly into RTO and ISO organized markets, but took a different approach with small utilities. Specifically, the Commission ordered

RTOs and ISOs to amend their market rules as necessary to accept bids from [aggregators of retail customers (ARCs)] that aggregate the demand response of: (1) the customers of utilities that distributed more than 4 million MWh in the previous fiscal year, and (2) the customers of utilities that distributed 4 million MWh 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 ARC. RTOs and ISOs may not accept bids from ARCs that aggregate the demand response of: (1) the customers of utilities that distributed more than 4 million MWh 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 ARC, or (2) the customers of utilities that distributed 4 million MWh 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 ARC.

Order No. 719-A, 128 FERC ¶ 61,059 at P 51, 60.

²⁰ Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 47. The Commission also required RTOs and ISOs to allow demand response resources to specify limits on the duration, frequency and amount of their service in their bids to provide ancillary services, in ways comparable to limits generators may specify in their bids. *Id.* at P 81.

²¹ *Id.* at P 274-276.

²² *Id.* The Commission also required each RTO and ISO's Independent Market Monitor to submit a similar report providing its views to the Commission. *Id.* at 274.

²³ *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241 (2007), *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228 (2009).

²⁴ These principles are coordination, openness, transparency, information exchange, dispute resolution, regional participation, economic planning studies, and cost allocation.

resources if they “are capable of providing the functions assessed in a transmission planning process, and can be relied upon on a long-term basis.”²⁵ On rehearing of Order No. 890, the Commission provided additional guidance to transmission providers, explaining that each provider must identify, as part of its “Attachment K” planning process, “how it will treat resources [transmission, generation and demand response] on a comparable basis and, therefore should identify how it will determine comparability for purposes of transmission planning.”²⁶

In the past year, the Commission has found that some transmission providers have not sufficiently addressed how transmission, generation and demand resources will be given comparable treatment during the transmission planning process.²⁷ In other cases, the Commission has found that while a transmission provider’s transmission planning process generally satisfies the requirement, it has failed to explicitly include all types of resources. In one case, a transmission provider identified when and where transmission customers may submit data to be evaluated in the transmission plan, but the Commission required the transmission provider to specify when and where other stakeholders may submit such data.²⁸ Similarly, the Commission found the use of the term “eligible customers” to describe who may request an economic study unduly restrictive, and required the transmission provider to amend its Attachment K to clarify that any stakeholder, including sponsors of transmission, generation and demand response, may request an economic study.²⁹

Demand Response Participation in RTO and ISO Wholesale Markets

FERC regulates six regional transmission organizations (RTOs) and independent system operators (ISOs): ISO New England, Inc. (ISO-NE), New York Independent System Operator, Inc. (NYISO), PJM Interconnection, Inc. (PJM), Midwest Independent Transmission System Operator, Inc. (Midwest ISO), Southwest Power Pool, Inc. (SPP), and the California Independent System Operator Corporation (CAISO). Since the summer of 2008, FERC has taken several actions concerning the participation of demand resources in the organized markets operated by these RTOs and ISOs.

Participation of Demand Resources in Capacity Markets

²⁵ Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 479.

²⁶ Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 at P 216. Attachment K is the section of a FERC-approved tariff that delineates a transmission provider’s transmission system planning process.

²⁷ In determining whether a transmission provider’s planning process complies with the comparability requirement, the Commission has generally focused on three issues: (1) where and when stakeholders can propose alternative solutions to identified needs, (2) that all stakeholders, not just transmission customers, may submit data to be evaluated in the transmission plan; and (3) how it will evaluate and select from among competing solutions such that all types of resources are considered on a comparable basis. See for example, *PJM Interconnection, LLC*, 127 FERC ¶ 61,187, at P 17 (2009) and *ISO New England*, 127 FERC ¶ 61,170, at P 13 (2009), where the Commission found that PJM Interconnection’s and ISO New England’s transmission planning processes complied with the comparability requirement because they sufficiently addressed the three issues discussed above.

²⁸ *Idaho Power Co.*, 128 FERC ¶ 61,064, at P 25-28 (2009).

²⁹ *Black Hills Power, Inc.*, 128 FERC ¶ 61,062, at P 10-11 (2009).

Demand resources continue to have the opportunity to participate in capacity markets in PJM and ISO-NE. Developments in the past year include:

PJM: PJM's Reliability Pricing Model (RPM) provides regular auctions for those load-serving entities that have not met their capacity needs through self-supply or bilateral contracts. In May 2009, PJM held an RPM base residual auction for the 2012 to 2013 delivery year. The total quantity of demand resources offered into this auction was 9,847.6 MW, which represents an increase of 496 percent over the demand resources offered into the prior auction.³⁰

Approximately 72 percent, or 7,047.3 MW, of these demand resources cleared the auction.³¹ By comparison, the relative prior year auction cleared 1,365 MW of demand resources.³²

ISO-NE: In December 2008, ISO-NE held its second Forward Capacity Market (FCM) auction to assure local and system-wide resource adequacy for the period between June 1, 2011 and May 31, 2012. The auction cleared with an excess supply of 4,755 MW above the installed capacity requirement of 35,528 MW.³³ Demand resources (which can include energy efficiency resources) accounted for 2,778 MW for the 2011/2012 capacity commitment period, or 8 percent of the total 37,283 MW that cleared the second FCM auction in which demand resources represented 6.7 percent of the total 34,077 MW that cleared.³⁴

The Commission has issued several orders relating to the participation of demand resources in organized capacity markets since the summer of 2008. A March 2009 order accepted PJM's proposal to allow for participation by energy efficiency resources in the RPM auctions. It also accepted PJM's proposal to encourage providers of demand response resources that are able to offer their resource three years forward in the RPM auction to do so, rather than wait to certify three months prior to the delivery year.³⁵ The Commission also accepted PJM's proposal to change the penalty structure in the RPM rules so that penalties more closely match the failure of a capacity resource to perform, and through that, improve the comparability between demand response and generation resources.³⁶

Improvements to Ancillary Services Markets

Since summer 2008, the Commission has issued several orders directed toward comparable treatment of demand resources in ancillary services markets.³⁷ The provisions of Order No. 719

³⁰ PJM INTERCONNECTION, INC., 2012/2013 RPM Base Residual Auction Results 1, 5 (2009), <http://www.pjm.com/markets-and-operations/rpm/~//media/markets-ops/rpm/rpm-auction-info/2012-13-base-residual-auction-report-document-pdf.ashx>.

³¹ *Id.*

³² *Id.* 3 & tbl.3B.

³³ ISO New England Inc., Informational Filing, Docket No. ER09-1282-000, at 28 (filed June 5, 2009).

³⁴ *Id.* 28.

³⁵ *PJM Interconnection*, 126 FERC ¶ 61,275, at P 84. Demand response resources that were certified as capacity resources in this fashion are known as Interruptible Load for Reliability resources.

³⁶ *Id.* at P 180.

³⁷ The Assessment does not estimate the potential for demand resources to be used as ancillary services.

were previously discussed. In NYISO, the Commission conditionally accepted tariff revisions that allow demand resources to offer operating reserves and regulation service into the NYISO-administered markets on terms comparable to generators, subject to further compliance filings.³⁸ In addition, the Commission approved revisions to NYISO's tariff to integrate energy storage devices into NYISO's day-ahead and real-time regulation service markets, noting that such devices benefit the NYISO's markets and further the Commission's goal of improving competition by allowing non-generating regulation service providers to participate in organized markets on terms comparable to generation resources.³⁹

In September 2008, the Commission accepted tariff revisions to ISO-NE's rules to extend and enhance the Demand Response Reserves Pilot Program that was set to expire September 30, 2008.⁴⁰ Originally implemented in 2006, the pilot allows a demand response resource of less than 5 MW to participate as reserve products and receive compensation on a similar basis to a generating resource.⁴¹

In February 2008, the Commission authorized the startup of Midwest ISO's ancillary services market.⁴² As part of its authorization, the Commission required Midwest ISO to evaluate whether adjustments to the ancillary services market procedures were necessary to remove barriers to the comparable treatment of demand response resources and new technologies in the regulating and operating reserves markets.⁴³ In December 2008, the Commission accepted the Midwest ISO's compliance filing that proposed a number of revisions aimed at ensuring that demand response is treated comparably.⁴⁴

Orders Addressing Demand Resource Participation in Energy and Other RTO and ISO Markets

In addition to orders focused on capacity and ancillary services markets, the Commission also issued orders on other demand response issues and programs in organized markets.

In orders concerning the Midwest ISO, the Commission addressed compensation for and availability of demand resources. The Commission accepted a Midwest ISO proposal to make stored energy resources and non-dispatchable demand response resources eligible for certain "make whole" payments that comparable resources are eligible to receive.⁴⁵ The Commission also approved emergency demand response participation in the Midwest ISO day-ahead market.⁴⁶

³⁸ *N. Y. Indep. Sys. Operator, Inc.*, 123 FERC ¶ 61,203, at P 2 (2008).

³⁹ *N. Y. Indep. Sys. Operator, Inc.*, 127 FERC ¶ 61,135, at P 18-21 (2009).

⁴⁰ *ISO New England, Inc.*, Docket No. ER08-1313-000 (Sept. 9, 2008) (unpublished letter order).

⁴¹ *Id.*

⁴² *Midwest Indep. Sys. Operator, Inc.*, 122 FERC ¶ 61,172 (2008).

⁴³ *Id.* at P 363, 365.

⁴⁴ *Midwest Indep. Sys. Operator, Inc.*, 125 FERC ¶ 61,319 (2008).

⁴⁵ *Midwest Indep. Sys. Operator, Inc.*, 125 FERC ¶ 61,318, at P 139 (2008).

⁴⁶ *Midwest Indep. Sys. Operator, Inc.*, 127 FERC ¶ 61,239, at P 20 (2009).

In March 2009, the Commission accepted the start of the CAISO's redesigned markets. Included as part of that redesign were modifications to CAISO's Participating Load Program. The Participating Load Program allows an entity to provide curtailable demand in particular CAISO markets pursuant to an agreement with the CAISO.⁴⁷ Changes included exempting participants in the Participating Load Program from the allocation of the costs associated with a backstop capacity process.⁴⁸ In accepting the CAISO's proposal, the Commission noted that the CAISO was working with interested stakeholders to integrate demand response resources into MRTU markets and to propose enhancements to demand response participation in the MRTU Tariff.⁴⁹ In July 2009, the Commission accepted a proposal by the Southwest Power Pool to incorporate demand resources into its real-time energy imbalance services market.⁵⁰

Retail Demand Response Activities

State governments, retail rate regulators, and individual utilities took important actions in support of demand response in the past year. These actions included issuance of legislation and state energy plans, regulatory commission decisions, and the deployment of demand response programs and enabling technologies by electric utilities. A brief summary of this activity follows.

States issue Strategic Energy Plans and Multi-sector Laws

At least ten states issued comprehensive long-term energy plans or passed legislation or regulations that will enable increased deployment of advanced metering infrastructure or demand response: California, Hawaii, Kentucky, Massachusetts, Michigan, Nebraska, New Jersey, Ohio, Pennsylvania, and Vermont. Table 1 depicts the range of relevant provisions or goals in these documents.

⁴⁷ Cal. Indep. Sys. Operator, FERC Electric Tariff, Appendix A, Fourth Replacement Vol. No. II, Second Revised Sheet Nos. 854 and 911.

⁴⁸ *Cal. Indep. Sys. Operator, Inc.*, 126 FERC ¶ 61,148, at P 20 (2009).

⁴⁹ *Id.* at P 27-29.

⁵⁰ Southwest Power Pool, Inc., 128 FERC ¶ 61,085 (2009).

Table 1: State Energy Plan, Vision, Law, or Regulations

State	Date	Name	Issuer, report type	Demand Response, peak reduction	AMI - Smart Meters / Grid	Dynamic Pricing	Energy Efficiency	Distributed Generation
California	Sep-08	Calif Long Term Energy Efficiency Strategic Plan	Public Utilities Commission: adopts IOU roadmap	√	√	√	√	√
Hawaii	Oct-08	Hawai'i Clean Energy Initiative	Governor, utilities, consumer advocate: energy policy MOU	√	√	√	√	√
Kentucky	Nov-08	Intelligent Energy Choices for Kentucky's Future	Governor, Energy Department: recommendations report	√	√	√	√	√
Massachusetts	Jul-08	Massachusetts Green Communities Act	Multi-sector energy law; some regulations pending	√	√	√	√	√
Michigan	Oct-08	Clean, Renewable, and Efficient Energy Act	Hybrid Renewable -Energy Efficiency Portfolio Standard	√	*	*	√	*
Nebraska	Jan-09	Nebraska State Energy Plan (Interim)	Interim plan from stakeholder process; under review	X	√	X	√	X
New Jersey	Oct-08	New Jersey Energy Master Plan (EMP)	Stakeholder process; implementation underway	√	√	X	√	√
Ohio	May-08 Apr-09	Alternative Energy Portfolio Standard	Hybrid RPS-EERS law Regulations issued	√	√	√	√	√
Pennsylvania	Oct-08	Energy Efficiency Resource Standard	Act 129 (2008 law)	√	√	√	√	√
Vermont	Jun-08	Comprehensive Energy Plan 2009 (draft)	VT Department of Public Service: 20-year plan	√	√	√	√	√

√ this element is included

X this element is not mentioned or explicitly excluded

* this element is included in a process outside named report or legislation. For example, many of the elements are in Michigan's earlier *21st Century Energy Plan* or follow-up initiatives, not in the 2008 law.

Source: FERC staff analysis of State Energy Office, legislative, and regulatory websites. Abbreviations used in the table include "IOU" which refers to investor-owned utility, "RPS" refers to Renewable Portfolio Standards and "EERS" refers to Energy Efficiency Resource Standard.

States and utilities took specific actions on AMI, smart meter pilot programs and deployments, dynamic pricing tariffs, automated demand response using enabling technologies, energy efficiency resource standards and decoupling tariffs, and smart grid initiatives. The following discussion highlights representative actions in these areas from June 2008 through July 2009.

Advanced Metering Infrastructure deployment

Commission staff collected information on AMI deployment activities by states and utilities to supplement the AMI deployment analysis in the Assessment. Twenty-six utilities in 19 states announced or pursued advanced metering pilots or full-deployment programs. Laws and policies in Hawaii, Massachusetts, and Pennsylvania laid the groundwork for pilot programs that could expand to statewide deployment by 2012.⁵¹ Utilities in Connecticut (Connecticut Light &

⁵¹ For example, the Massachusetts smart meter pilot includes the deployment of 5,000 meters. In Pennsylvania, Act 129 of 2008 mandates that the Pennsylvania Public Utility Commission and electric utilities pursue energy efficiency, conservation, a smart meter plan, AMI and dynamic pricing. See Institute for Electric Efficiency, *Utility-Scale Smart Meter Deployments, Plans, Proposals* (May 2009)

Power), the District of Columbia (Pepco's "PowerCentsDC"), Oregon (Portland General Electric), and Maryland and West Virginia (Allegheny Power) announced or began smart meter pilot programs.⁵² In Illinois, Commonwealth Edison filed for approval to install 141,000 advanced meters in homes and to study consumer behavior before committing to a full roll-out.⁵³ At least nine utilities in four states, satisfied with AMI pilot program results, began or completed full service-territory deployments of AMI, including two Arizona utilities, three California utilities, Idaho Power, and three Texas utilities.

Three multistate utility holding companies announced plans to deploy AMI in their operating utilities or began smart meters installation: Southern Company (Southern), Duke Energy (Duke), and Pepco Holdings, Inc. (Pepco Holdings). Southern reached a one-million smart meter milestone in March 2009,⁵⁴ and intends to install 4.3 million smart meters and deploy AMI for its customers at Alabama Power, Georgia Power, Gulf Power, and Mississippi Power by 2013.⁵⁵ Duke Energy Indiana reached a settlement with Indiana's Office of Utility Consumer Counsel for its smart grid proposal; it then sought regulatory approval for its proposed AMI and smart grid implementation plans.⁵⁶ Duke awaits approval for similar plans in Ohio and South Carolina.⁵⁷ AMI development is central to Pepco Holdings' smart grid plan.⁵⁸ Pepco Holdings' Delaware subsidiary, Delmarva Power, won approval to install smart meters and recover related costs. Their customers will start to receive smart meters in late 2009.⁵⁹

http://www.edisonfoundation.net/iee/issueBriefs/SmartMeter%20Rollouts_0509.pdf (summarizing investor-owned utilities' and some public power utilities smart meter plans).

⁵² Id.

⁵³ Commonwealth Edison Co., "Petition to approve an Advanced Metering Infrastructure Pilot Program and Associated Tariffs," P09-0263 (filed with Illinois Commerce Commission, June 1, 2009).

⁵⁴ Press Release, Southern Co., Southern Company Reaches Milestone in Smart Meter Program with 1 Million Installations (March 5, 2009), *available at* <http://southerncompany.mediaroom.com/index.php?s=43&item=1870>.

⁵⁵ Southern Company Signs One of the Largest AMI Contracts in History, [www.METERING.COM](http://www.metering.com), Jan 15, 2008, <http://www.metering.com/node/11390> (Southern Company signed a contract to provide smart meters and AMI to its customers over the next five years.).

⁵⁶ Duke Energy Indiana SmartGrid Settlement, IURC Cause No. 43501, June 4, 2009, (Duke Energy Indiana submitted the settlement the same day that it submitted its request to the Indiana Utility Regulatory Commission for approval of an alternative rate plan and cost recovery proposal for the AMI and SmartGrid deployment).

⁵⁷ In 2008, Duke requested approval of plans for smart meter deployment in Indiana and Ohio, with plans to do so in the future in Kentucky and the Carolinas. See, e.g., Press Releases, Duke Energy, "Public Utilities Commission of Ohio Approves Settlement Agreement for Duke's Energy Security Plan" (December 17, 2008); and Press Release, Duke Energy, "Duke Energy Partners with Cisco to Fast-Track Development of Utility's 'Smart Grid' (June 9, 2009), ("the company also is laying the groundwork to bring large-scale smart grid technology to three other states it serves – North Carolina, South Carolina, and Kentucky.").

⁵⁸ Pepco Holdings Inc., Powering a Sustainable Future: 2008 Annual Environmental Sustainability Report (May 4, 2009). In its "Blueprint for the Future," Pepco Holdings lays out a smart grid vision that includes smart meters, direct load control, distribution monitoring and control, outage detection, and home automation for its 1.9 million customers in Delaware, Maryland, New Jersey, and Washington D.C.

⁵⁹ On September 16, 2008, the Delaware Public Service Commission approved a regulatory asset cost recovery and appropriate operating costs associated with AMI deployment and other DR equipment. See, e.g., Press Release, PHI, "PHI Awards Major Smart Technology Contracts" (March 25, 2009).

Dynamic pricing programs grow as corollary to smart meter deployment

Dynamic pricing refers to the family of rates that offer customers time-varying electricity prices on a day-ahead or real-time basis. With dynamic pricing, electricity prices are either not known with certainty ahead of time, or known higher prices occur at times that are not known ahead of time. As stated in the Assessment, “the rates are dynamic in the sense that prices change in response to events such as high-priced hours, unexpectedly hot days, or reliability conditions.”⁶⁰ Dynamic pricing programs include critical peak pricing (CPP) programs, peak time rebates (PTR), and real-time pricing programs (RTP).

Nearly every retail regulatory filing or approval for AMI in the past year had a corresponding request for approval of a dynamic pricing tariff. Pennsylvania’s Energy Efficiency Resource Standard requires advanced metering implementation and time-of-use or real-time pricing tariff offers to customers with smart meters.⁶¹ AMI or smart grid pilots that incorporate dynamic pricing tariffs include Pepco Holdings’ PowerCentsDC (RTP, CPP and PTR) and Connecticut Light & Power (CPP and PTR). Pepco Holdings and Duke Energy filed dynamic pricing tariff requests in all states where they filed for AMI cost recovery.

State and local policies that encourage demand resources

States also took action to promote or require peak load reductions. Four states passed peak load reduction targets this reporting year: Maine, Maryland, Ohio, and Pennsylvania. California, Connecticut, and Illinois passed them earlier. Florida, D.C., and New Jersey proposed targets, but had not issued regulations as of the date of this report. Six states—Pennsylvania, Maryland, New York, New Mexico, Ohio, and Iowa—adopted or enhanced energy efficiency resource standards this year that include demand response.⁶² In the southeast, the Tennessee Valley Authority (TVA) adopted an “Energy Efficiency and Demand Response Plan” with goals to cut peak demand and reduce energy consumption 25 percent over five years in its seven-state service area, using energy efficiency, demand response and smart grid technologies.⁶³ Among the states with an integrated resource plan or other procurement order that requires utilities to include or study demand response resources, dynamic pricing, advanced metering or other enabling technologies are Connecticut, Delaware, Idaho, Iowa, Nevada, Oregon, Rhode Island, Utah, and Washington.

⁶⁰ Assessment, *supra* note 4, 21.

⁶¹ Penn. Pub. Util. Comm’n., Act 129 of 2008: Overview and Implementation, Presentation at MADRI Steering Committee (March 5, 2009), http://sites.energetics.com/madri/pdfs/Act_129_Presentation.pdf.

⁶² For an overview of energy efficiency resource standards by state, see <http://www.ferc.gov/market-oversight/mkt-electric/overview/elec-ovr-eeeps.pdf>

⁶³ On May 19, 2008, TVA’s board approved an *Energy Efficiency and Demand Response Plan* and a *2008 Environmental Policy*, May 19, 2008. The plan and policy provides for a 25% load growth reduction target by September 30, 2012. In addition, TVA signed a contract with EnerNOC to provide 110 MW of demand response capacity for a program it will initially roll-out to large commercial and industrial customers of four power distributors. Press Release, EnerNOC, EnerNOC Signs Contract with Tennessee Valley Authority (June 17, 2008), <http://www.tva.gov/environment/policy.htm>.

Local entities such as public power systems also recognize the value of demand resources. American Public Power Association (APPA) recently adopted a resolution⁶⁴ that, among other things, called on public power systems to include cost-effective demand response measures (such as automatic load control devices, time-of-use rates, and “smart” appliances) as an integral component in their respective power supply portfolios and integrated resource plans. APPA’s resolution comes in response to a growing number of challenges facing public power systems. Increased fuel costs have made purchasing power more expensive and difficult to predict. In addition, financing new generation resources has become more expensive given the recent downturn in capital markets. Public power systems also believe they may be faced with a more difficult power supply planning process should Congress enact climate change legislation or a nation-wide renewable energy standard. APPA expects that including demand resources in power supply portfolios and resource plans will produce benefits such as reduced costs for all retail customers by reducing the need for expensive peaking power supply contracts and new peaking generation.

Smart grid initiatives begun by investor-owned and municipal utilities

While national standards for smart grid interoperability are being developed, states and municipalities initiated smart grid task forces and pilot projects. Many of these initiatives explicitly target or include demand response. Examples of state-level explorations are “Smart Grid Maryland,” Michigan’s “Smart Grid Collaborative,” and the Illinois smart grid workshop process. With a Department of Energy grant, the Maryland Energy Administration (MEA) initiated “Smart Grid Maryland” to study the costs and benefits of a smart grid system and the relationships among demand response, energy efficiency, transmission, and smart grid technologies.⁶⁵ Michigan’s Smart Grid Collaborative grew out of Michigan’s 21st Century Energy Plan and issued a report recommending that the Michigan Public Service Commission write guidelines to include interoperability and AMI cost recovery.⁶⁶ In April 2009, the Illinois Commerce Commission initiated a smart grid workshop process to examine smart grid technology.⁶⁷

Several utilities completed or began to test smart grid technologies in pilot cities throughout the United States. For instance, Baltimore Gas & Electric ran the pilot “Smart Energy Savers Program” from November 2007 to November 2008, which included testing two AMI

⁶⁴ Press Release, APPA, APP Urges Public Power Systems to Incorporate Demand Response as an Integral Component in Their Power Supply Portfolios (June 19, 2009), http://www.appanet.org/files/PDFs/APPA%202009%20Resolutions_formatted.pdf.

⁶⁵ The Department of Energy awarded MEA a \$461,793 grant on September 18, 2008. MEA is using the grant to calculate the benefits of a smart grid system for Maryland. See Jenn Klima Gallicchio & Jennette Brinch, Introduction to the Smart Grid Maryland Project, Presented at the Maryland Smart Grid Stakeholders Meetings (May 14, 2009) (<http://www.smartgridmd.org/events/Documents/Gallicchio%20-%20Brinch%20-3.pdf>) (describing its work so far).

⁶⁶ Michigan Pub. Serv. Comm’n. Report on the Smart Grid Collaborative U-15278 (April 29, 2008), available at: <http://efile.mpsc.cis.state.mi.us/efile/docs/15278/0007.pdf>.

⁶⁷ Illinois Smart Grid Initiative, Empowering Customers Through a Modern Electric Grid (April 2009), <http://www.ilsmartgrid.org> (identifying the benefits of a modernized electric grid, and mapping out a policy for achieving that goal).

technologies, direct load control with enabling technologies, and a “Smart Energy Pricing Pilot.”⁶⁸ “Energy Smart Miami” will deploy more than one million smart meters to all homes and most businesses in Miami-Dade County.⁶⁹ Xcel Energy launched the “Smart Grid City” in March 2008 in Boulder, Colorado and expects to complete this multiphase project in December 2009.⁷⁰ Austin Energy’s “Pecan Street Project” is building the technological foundation to manage its smart grid.⁷¹ Austin Energy began installing smart meters in April 2008.⁷² In addition, Austin Energy is evaluating the performance of 70,000 installed smart thermostats and has a small pilot program to model the impact of plug-in hybrid electric vehicles.⁷³

(F) Regulatory barriers to improved customer participation in demand response, peak reduction, and critical period pricing programs

The Assessment contains a detailed review of barriers, including regulatory barriers to demand response (in Chapter VI), along with recommendations on how to address the barriers (in Chapter VII). For example, the Assessment recommends:

- sharing of information on effective program designs,
- increasing customer awareness of and education about demand response programs,
- coordinating wholesale and retail demand response strategies,
- improving and expanding interoperability and open standards,
- coordinating demand response and energy efficiency policies, and
- articulating clearly the role of demand response in operational and long-term planning, and the recovery of associated costs.

⁶⁸ Wayne Harbaugh, Vice President - Pricing and Regulatory Services, BGE, BGE Smart Energy Savers Program, Presentation at PJM Symposium on Demand Response II (May 12, 2008).

⁶⁹ See Press Release, City of Miami, Miami Proposes to Lead the Nation in Energy Efficiency with \$200 Million Smart Grid Initiative, (April 20, 2009), *available at* http://www.energysmartmiami.com/files/City_of_Miami_News_Release_Energy_Smart_Miami_FINAL_4_20_09.pdf.

⁷⁰ See Xcel Energy’s design plan and timeline at <http://smartgridcity.xcelenergy.com/media/pdf/SmartGridCityDesignPlan.pdf>.

⁷¹ See Austin Energy, 2008 Strategic Planning Update 11 (May 19, 2009), http://www.austinenergy.com/About%20Us/Newsroom/Strategic%20Plan/strategicPlanningUpdate_2008.pdf; Austin City Council, Resolution No. 20080925-084 (September 25, 2008) (resolving to work with stakeholders and other groups “to conduct an analysis of system improvements, technology advances, business models, and public investments that would enable Austin Energy to more fully develop its capacity for the distributed generation of clean energy including the potential to develop new products and revenue streams, in furtherance of the recently announced goals of the Pecan Street Project”).

⁷² See Austin Energy, *supra* note 65; Austin City Council, Res. 20080925-084.

⁷³ See Austin Energy, *supra* note 65; Austin City Council, Res. 20080925-084.



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