Assessment of

Demand Response AND Advanced Metering

Federal Energy Regulatory Commission *Staff Report*

December 2016

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ACKNOWLEDGEMENTS

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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)

December 2016

Chapter 1: Introduction

This report is the Federal Energy Regulatory Commission staff's (FERC or Commission staff's) eleventh annual report on demand response and advanced metering required by section 1252(e)(3) of Energy Policy Act of 2005 (EPAct 2005). It is based on publicly-available information and discussions with market participants and industry experts. Based on the information reviewed, it appears that:

- Deployment of advanced meters continues to increase throughout the country,[1] and advanced meters are the predominant metering technology installed and operational throughout the United States. According to the Energy Information Administration (EIA),[2] 58.5 million advanced meters were operational nationwide out of a total of 144.3 million meters, indicating a 40.6 percent penetration rate;
- In the organized wholesale markets, the contribution of potential peak reduction[3] to meeting peak demand increased to 6.6 percent in 2015 from 6.2 percent in 2014;
- The North American Electric Reliability Corporation (NERC) has developed and approved four new metrics for assessing demand response, and intends to continue its efforts to improve demand response data collection to provide information on how demand response contributes to reliability;
- The North American Energy Standards Board (NAESB) developed and ratified voluntary business standards that facilitate the ability of advanced meters and other utility and

[1] As defined by the U.S. Energy Information Administration (EIA), Advanced Metering Infrastructure (AMI) Meters are

"Meters that measure and record usage data at a minimum, in hourly intervals and provide usage data at least daily to energy companies and may also provide data to consumers. Data are used for billing and other purposes. Advanced meters include basic hourly interval meters and extend to real-time meters with built-in two-way communication capable of recording and transmitting instantaneous data."

See EIA, Form EIA-861: Annual Electric Power Industry Report Instructions, *available at* http://www.eia.gov/survey/form/eia_861/instructions.pdf.

[2] EIA, Form EIA-861 Advanced_Meters_2014 data file (re-released January 13, 2016).

[3] Potential peak reduction (or potential peak demand savings) refers to "the total demand savings that could occur at the time of the system peak hour assuming all demand response is called." EIA, Form EIA-861 Instructions, Schedule 6, Part B.

third-party grid devices to communicate directly with each other and exchange information; and

- On January 25, 2016, the U.S. Supreme Court issued its decision in *FERC v. Electric Power Supply Association*, upholding the Commission's authority under the Federal Power Act to adopt Order No. 745.[4]

The report addresses 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 (Chapter 2);
(B) existing demand response programs and time-based rate programs (Chapter 5);
(C) the annual resource contribution of demand resources (Chapter 3);
(D) the potential for demand response as a quantifiable, reliable resource for regional planning purposes (Chapter 4);
(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 (Chapter 5); and
(F) regulatory barriers to improved customer participation in demand response, peak reduction and critical period pricing programs (Chapter 6).

[4] 136 S. Ct. 760 (2016) ("*EPSA*")

Chapter 2: Saturation and penetration rate of advanced meters

This chapter reports on penetration rates for advanced meters, and developments related to advanced metering. As summarized in Table 2-1, recent data indicate that advanced meter penetration rates and the number of advanced meters in operation continue to increase in the United States. This trend is robust across several data sets.

Table 2-1: Estimates of Advanced Meter Penetration Rates

Data Source	Data As Of	Number of Advanced Meters (millions)	Total Number of Meters (millions)	Advanced Meter Penetration Rates (advanced meters as a % of total meters)
2008 FERC Survey	Dec 2007	6.7 [1]	144.4 [1]	4.7%
2010 FERC Survey	Dec 2009	12.8 [2]	147.8 [2]	8.7%
2012 FERC Survey	Dec 2011	38.1 [3]	166.5 [3]	22.9%
2011 Form EIA-861 (re-released)	Dec 2011	37.3 [4]	144.5 [4]	25.8%
Institute for Electric Efficiency	May 2012	35.7 [5]	144.5 [4]	24.7%
2012 Form EIA-861	Dec 2012	43.2 [6]	145.3 [6]	29.7%
Institute for Electric Innovation	July 2013	45.8 [7]	145.3 [6]	31.5%
2013 Form EIA-861 (re-released)	Dec 2013	51.9 [8]	138.1 [8]	37.6%
Institute for Electric Innovation	July 2014	50.1 [9]	138.1 [8]	36.3%
2014 Form EIA-861	Dec 2014	58.5 [10]	144.3 [10]	40.6%

Sources:

[1] FERC, Assessment of Demand Response and Advanced Metering staff report (December 2008).

[2] FERC, Assessment of Demand Response and Advanced Metering staff report (February 2011).

[3] FERC, Assessment of Demand Response and Advanced Metering staff report (December 2012).

[4] EIA, Form EIA-861 file_2_2011 and file_8_2011 (re-released May 20, 2014). The number of ultimate customers served by full-service and energy-only providers is used as a proxy for the total number of meters. Advanced meters are defined as advanced metering infrastructure (AMI) meters.

[5] The Edison Foundation Institute for Electric Efficiency, Utility-Scale Smart Meter Deployments, Plans & Proposals (May 2012).

[6] EIA, Form EIA-861 and Form EIA-861S: retail_sales_2012 and advanced_meters_2012 data files (October 29, 2013). The number of ultimate customers served by full-service and energy-only providers is used as a proxy for the total number of meters. Advanced meters are defined as AMI meters.

[7] The Edison Foundation Institute for Electric Innovation, Utility-Scale Smart Meter Deployments: A Foundation for Expanded Grid Benefits (August 2013).

[8] EIA, Form EIA-861: Advanced_Meters_2013 data file (re-released June 8, 2015). The number of total meters—including AMI, AMR and standard electromechanical meters—was reported for the first time in 2013. Therefore, we no longer use the number of customers as a proxy. *See* note 4 above and *Form EIA-861Annual Electric Power Industry Report Instructions*, Schedule 6, Part D, *available at* http://www.eia.gov/survey/form/eia_861/proposed/2013/instructions.pdf.

[9] The Edison Foundation Institute for Electric Innovation, Utility-Scale Smart Meter Deployments: Building Block Of The Evolving Power Grid (September 2014).

[10] EIA, Form EIA-861: Advanced_Meters_2014 data file (re-released January 13, 2016).

Note: Commission staff has not independently verified the accuracy of EIA or Edison Foundation data. Values from source data are rounded for publication.

According to 2014 EIA data,[5] 58.5 million advanced meters were operational nationwide out of a total of 144.3 million meters, indicating a 40.6 percent penetration rate. This penetration of advanced meters represents significant growth over the previous year, when EIA reported that

[5] EIA, Form EIA-861 Advanced_Meters_2014 data file (re-released January 13, 2016).

51.9 million advanced meters were operational out of a total of 138.1 million meters, representing a 37.6 percent penetration rate.[6]

Table 2-2 below provides estimated advanced metering penetration rates by NERC region[7] and retail customer class. Advanced meters represent more than half of the meters in three regions: 79.7 percent of meters in Texas Reliability Entity (TRE), 60.4 percent in Western Electricity Coordinating Council (WECC), and 56.9 percent in Florida Reliability Coordinating Council (FRCC). The largest growth in advanced meter penetration from 2013 to 2014 took place in ReliabilityFirst Corporation (RFC) and SERC Reliability Corporation (SERC), which saw increases of approximately 7 and 9 percentage points, respectively.

Table 2-2: Estimated Advanced Meter Penetration by Region and Customer Class (2014)

Region	Customer Class			
	Residential	Commercial	Industrial	All Classes
AK	9.6%	3.6%	0.0%	8.8%
FRCC	56.3%	61.7%	74.5%	56.9%
HI	6.0%	7.0%	19.9%	6.1%
MRO	18.8%	16.1%	22.4%	18.5%
NPCC	9.6%	9.4%	15.7%	9.6%
RFC	31.7%	23.4%	16.6%	30.8%
SERC	36.0%	33.2%	32.5%	35.6%
SPP	40.4%	39.5%	33.6%	40.2%
TRE	79.5%	82.7%	43.7%	79.7%
WECC	60.6%	59.0%	54.0%	60.4%
Unspecified	21.9%	21.4%	70.4%	22.8%
All Regions	**40.9%**	**38.6%**	**36.5%**	**40.6%**

Sources: EIA, 2014 Form EIA-861 Advanced_Meters_2014 data file.

Note: Although some entities may operate in more than one NERC Region, EIA data have only one NERC region designation per entity. The "unspecified" category represents respondents to the EIA-861 short form, which were not required to report a NERC region. Commission staff has not independently verified the accuracy of EIA data.

Overall, Table 2-2 above indicates a slightly higher percentage of residential customers have an advanced meter (40.9 percent) than do customers in the commercial (38.6 percent) or industrial (36.5 percent) customer classes.

[6] *Id*. EIA data also reveals that advanced meters are now the predominant metering technology installed and operational throughout the United States.

[7] NERC comprises eight regional entities in the lower 48 states: the Florida Reliability Coordinating Council (FRCC), Midwest Reliability Organization (MRO), Northeast Power Coordinating Council (NPCC), ReliabilityFirst Corporation (RFC), SERC Reliability Corporation (SERC), Southwest Power Pool RE (SPP), Texas Reliability Entity (TRE), and Western Electricity Coordinating Council (WECC). The states of Alaska (AK) and Hawaii (HI) are not subject to NERC oversight.

Developments and issues in advanced metering

Collaborative industry-government efforts

On March 7, 2016, NAESB developed and ratified[8] voluntary business standards[9] that facilitate the ability of advanced meters and other utility and third-party grid devices (e.g., relays, inverters, reclosers) to communicate directly with each other and exchange information.[10] With the proliferation of intelligent devices with a variety of communication protocols newly deployed within substations and transmission and distribution lines, these standards, NAESB's Open Field Message Bus (OpenFMB) Model Business Practices, facilitate the resolution of data delay issues, improve situational awareness and interoperability requirements,[11] and provide for "distributed intelligence opportunities to manage local grids in the most efficient way based on local resources and conditions."[12] Participants in the standards development process included the National Association of Regulatory Utility Commissioners and the National Institute of Standards and Technology.[13]

State legislative and regulatory activity

Electric utilities continue to deploy advanced meters and are developing new energy services and technologies, including mobile applications that enable customers to view their energy consumption, interact with utilities, and manage their electricity bills. Some utilities are experimenting with different pilot programs to encourage customer engagement and facilitate the incorporation of demand response technologies through advanced metering infrastructure.

- **Alabama.** In February 2016, Baldwin County Electric Membership Corporation (Baldwin EMC), the largest cooperative electric utility in Alabama,[14] initiated

[8] The NAESB process is open to any interested party, and parties can participate and contribute to the standards development regardless of NAESB membership status.

[9] Press Release, NAESB Announcement Concerning the Open Field Message Bus Model Business Practices, NAESB, March 15, 2016, *available at* https://www.naesb.org//pdf4/031516press_release.pdf.

[10] Duke Energy, Leading Advancements in Interoperability: Open Field Message Bus (OpenFMB™) Interoperability Framework with a Microgrid Implementation, Jan. 2016, p. 3, *available at* https://www.duke-energy.com/pdfs/interoperability-brochure.pdf.

[11] NAESB, 2015 Retail Annual Plan Item 9.a/R14008: Develop model business practices to support OpenFMB architecture for interoperable data exchange between distributed power systems devices on the electric grid's field area networks, Ratified March 7, 2016, pp. 5=6, *available at* https://www.naesb.org/pdf/ordrform.pdf.

[12] Duke Energy, Leading Advancements in Interoperability: Open Field Message Bus (OpenFMB™) Interoperability Framework with a Microgrid Implementation, Jan. 2016, p. 3.

[13] Press Release, NAESB Announcement Concerning the Open Field Message Bus Model Business Practices, NAESB, March 15, 2016, *available at* https://www.naesb.org//pdf4/031516press_release.pdf.

[14] "Baldwin EMC Recognized by CS Week for Advanced Metering, Load Management Projects," Baldwin EMC, (May 10, 2016), *available at* http://www.baldwinemc.com/baldwin-emc-recognized-by-cs-week-for-advanced-metering-load-management-projects/.

deployment of 20,000 advanced meters.[15] Baldwin EMC serves over 73,000 customers.[16]

- **Arizona.** The Arizona Public Service Company (APS) filed a rate case application on June 1, 2016, that included a proposed advanced meter opt-out fee ($70 for set up and $15 per month meter reading fee).[17] APS included the advanced meter opt-out fee in response to the Arizona Corporation Commission's (ACC) decision to include consideration of advanced meter opt-out fees as a component of the ACC's comprehensive review of the APS general rate case.[18]

- **Colorado.** On August 3, 2016, Xcel Energy filed a request with the Colorado Public Utilities Commission (PUC) to approve a $500 million project proposal that would replace all retail meters with advanced meters.[19] The proposed project is scheduled to roll out the advanced meters from 2017 to 2021, pending Colorado PUC approval.[20] Xcel serves approximately 1.4 million electricity customers throughout Colorado.[21]

- **Connecticut.** The Connecticut Municipal Electric Energy Cooperative (CMEEC) deployed over 38,000 advanced meters as of June 2015.[22] The deployment is part of a smart grid project (ConnSMART Program) that includes four municipal utilities.[23] The CMEEC intends to provide all customers with access to advanced meters, with the goal of realizing operational efficiencies, improving service reliability, and enhancing customer service.[24]

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[15] "Baldwin EMC Begins Deploying Landis+Gyr Load Management System," Landis+Gyr, (February 15, 2016), *available at* http://www.landisgyr.com/baldwin-emc-begins-deploying-landisgyr-load-management-system/.

[16] Baldwin EMC, 2014 Annual Report, October 2015, *available at* http://www.baldwinemc.com/wp-content/uploads/52624-BEMC-AnnReport-proof4.pdf.

[17] In the Matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return Thereon, to Approve Rate Scheduled Designed to Develop such Return, Arizona Public Service Company Rate Application, Docket No. E-01345A-16-0036 (ACC June 1, 2016), *available at* http://images.edocket.azcc.gov/docketpdf/0000170846.pdf.

[18] In the Matter of the Application of Arizona Public Service Company for Approval of Automated Meter Opt-Out Service Schedule 17, Decision No. 75047, Docket No. E-01345A-13-0069, (ACC Apr. 30, 2015), pp. 16-17, *available at* http://images.edocket.azcc.gov/docketpdf/0000160782.pdf.

[19] Xcel proposes massive, $500 million upgrade of Colorado electric meters, (Denver Business Journal August 3, 2016), *available at* http://www.bizjournals.com/denver/blog/earth_to_power/2016/08/xcel-energy-proposes-massive-500m-upgrade-of.html?ana=RSS%26s%3Darticle_search&utm_source=feedburner&utm_medium=feed&utm_campaign=Feed%3A+bizj_denver+%28Denver+Business+Journal%29.

[20] Xcel proposes massive, $500 million upgrade of Colorado electric meters, (Denver Business Journal August 3, 2016).

[21] Who We Are, (Xcel Energy 2016), *available at* https://www.xcelenergy.com/company/corporate_responsibility_report/who_we_are.

[22] Smart Grid Investment Grant Final Project Description, Connecticut Municipal Electric Energy Cooperative Smart Grid Project at 1, (U.S. DOE, Office of Electricity Delivery and Energy Reliability June 2015).

[23] *Id*.

[24] *Id*.

- **Florida.** Florida Power & Light (FPL) restored power to more than 110,000 customers affected by Hurricane Hermine within 24 hours.[25] FPL credits investments in system hardening, infrastructure upgrades, and technological investments, including advanced meters, in reducing the number of customer outages and faster service restoration.

- **Hawaii.** The Hawaiian Electric Company, Inc., Hawaii Electric Light Company Inc., and Maui Electric Company, Ltd., filed an application with the Hawaii Public Utilities Commission (PUC) for the approval to commit funds for the Smart Grid Foundation Project, to defer certain costs, and to recover capital and deferred costs through a Renewable Energy Infrastructure Surcharge.[26] The companies estimate a cost of $340 million to implement the project, with roughly $180 million of that dedicated to advanced meter infrastructure in the first phase of the project. The proposal includes deployment of advanced meters across all five of the companies' service territory islands (Oahu, Hawai'i Island, Maui, Moloka'i and Lana'i). The companies target advanced meter installations for more than 97 percent of their customers (equal to approximately 467,000 installations).[27]

- **Illinois.** In March 2016, the Illinois Commerce Commission (ICC) ordered Ameren Illinois and Commonwealth Edison Company (ComEd) to provide customers with electronic access to their own electricity usage data gathered through advanced meters.[28] The ICC order establishes a process by which consumers can obtain and control access to their electricity data, prescribing a standardized authorization form and the Green Button Connect My Data program[29] as the method of electronic delivery.[30]

- **Indiana.** In December 2015, after reaching a settlement with various parties, Duke Energy filed a seven-year transmission, distribution, and storage system improvement

[25] News Release, Florida Power & Light, Florida Power & Light Company completes service restoration to customers affected by Hurricane Hermine in line with pre-storm commitment, Sept. 3, 2016, *available at* http://newsroom.fpl.com/2016-09-03-Florida-Power-Light-Company-completes-service-restoration-to-customers-affected-by-Hurricane-Hermine-in-line-with-pre-storm-commitment.

[26] In the Matter of the Application of the Hawaiian Electric Companies for Approval to Commit Funds in Excess of $2,500,00 for the Smart Grid Foundation Project and Related Requests. Docket No. 2016-0087, (Hawaii PUC March 31, 2016), *available at* https://www.hawaiianelectric.com/Documents/clean_energy_hawaii/smart_grid/dkt_2016-0087_20160331_SGF_project_book_1.pdf.

[27] In the Matter of the Application of the Hawaiian Electric Companies for Approval to Commit Funds in Excess of $2,500,00 for the Smart Grid Foundation Project and Related Requests. Docket No. 2016-0087 at 25, (Hawaii PUC March 31, 2016).

[28] Investigation into the Customer Authorization Required for Access by Third Parties Other Than Retail Electric Suppliers to Advanced Metering Infrastructure Interval Meter Data, Order No.15-0073, (ICC March 23, 2016), *available at* https://www.icc.illinois.gov/downloads/public/edocket/424241.pdf.

[29] The Green Button Connect My Data program allows customers to automatically send their energy usage data to third-party providers, giving customers additional options on how to view and use their energy usage data.

[30] ICC, Infrastructure Investment Plans, *available at* https://www.icc.illinois.gov/electricity/utilityreporting/InfrastructureInvestmentPlans.aspx.

plan with the Indiana Utility Regulatory Commission (URC).[31] As part of the proposal, Duke Energy agrees to reduce the level of capital investment recovered through customers' monthly bills, including $192 million for advanced meters.[32] Duke Energy retains the ability to pursue advanced meters and defer the associated costs for Indiana URC consideration in a future rate case rather than through a monthly bill tracker, and also agrees to explore energy efficiency pilot programs if it pursues advanced meters in the future.[33] In a June 29, 2016 order, the Indiana URC approved the plan.[34]

- **Kansas.** On September 24, 2015, the Kansas Corporation Commission (KCC) approved Westar Energy's Stipulation & Agreement, [35] which will replace all analog meters with advanced meters over a period of five years.[36] As of December 31, 2015, Westar had installed 250,000 advanced meters, which benefitted customers by providing timely service without sending out trucks on 91,000 automated service calls.[37] The company has a customer base of approximately 700,000 customers.[38]

- **Kentucky.** On April 25, 2016, Duke Energy filed an application with the Kentucky Public Service Commission (PSC) to replace its existing meters with advanced meters.[39]

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[31] *Verified Petition of Duke Energy Indiana, Inc. for Approval of Petitioner's 7-Year Plan for Eligible Transmission, Distribution, and Storage System Improvements*, Verified Petition, Cause No. 44720, (Indiana URC Dec. 7, 2015), *available at* https://myweb.in.gov/IURC/eds/Modules/IURC/CategorySearch/viewfile.aspx?contentid=0900b631801cf9ce.

[32] *Verified Petition of Duke Energy Indiana, Inc. for Approval of Petitioner's 7-Year Plan for Eligible Transmission, Distribution, and Storage System Improvements*, Cause No. 44720, Appendix A at 1, (Indiana URC Dec. 7, 2015).

[33] Press Release, Duke Energy, Duke Energy Indiana reaches settlement to modernize its statewide electric grid (March 7, 2016), *available at* http://news.duke-energy.com/releases/duke-energy-indiana-reaches-settlement-to-modernize-its-statewide-electric-grid.

[34] *Verified Petition of Duke Energy Indiana, Inc. for Approval of Petitioner's 7-Year Plan for Eligible Transmission, Distribution, and Storage System Improvements*, Order of the Commission, Cause No. 44720, (Indiana URC June 29, 2016), *available at* https://myweb.in.gov/IURC/eds/Modules/Ecms/Cases/Docketed_Cases/ViewDocument.aspx?DocID=0900b631801da2fe.

[35] In the Matter of the Publication of Westar Energy, Inc. and Kansas Gas and Electric Company to Make Certain Changes in Their Charges for Electric Service, Docket No. 15-WSEE-115-RTS, Order Approving Stipulation and Agreement (KCC Sept. 24, 2015), *available at* http://estar.kcc.ks.gov/estar/ViewFile.aspx?Id=29b7b55e-b40c-4f66-9335-153bfe44a81e.

[36] In the Matter of the Publication of Westar Energy, Inc. and Kansas Gas and Electric Company to Make Certain Changes in Their Charges for Electric Service, Docket No. 15-WSEE-115-RTS at 2, Direct Testimony of Hal Jensen (KCC Mar. 2, 2015), *available at* http://estar.kcc.ks.gov/estar/ViewFile.aspx?Id=91a694e6-ee25-4156-b6c1-c2159533e338.

[37] Westar Energy, Digital Meter Upgrade Program, *available at* https://www.westarenergy.com/Portals/0/Resources/Documents/PDFs/AMI_Summary.pdf.

[38] Westar Energy, Westar at a Glance, *available at* https://www.westarenergy.com/westar-at-a-glance.

[39] The Application of Duke Energy Kentucky, Inc., for (1) a Certificate of Public Convenience and Necessity Authorizing the Construction of an Advanced Metering Infrastructure; (2) Request for Accounting Treatment; and (3) All Other Necessary Waivers, Approvals, and Relief, Case No. 2016-00152, Application, (Kentucky PSC Apr. 25, 2016), *available at* http://psc.ky.gov/pscecf/2016-00152/debbie.gates%40duke-energy.com/04252016034135/Case_No._2015-00152_Application.pdf.

Duke Energy proposes to install approximately 143,000 advanced meters over two years, at an estimated cost of $38 million.[40]

- **Maine.** In January 2016, Maine's Supreme Judicial Court affirmed a Maine Public Utilities Commission (MPUC) finding that Central Maine Power Company's (CMP) advanced metering infrastructure system poses no credible threat to the health and safety of CMP's customers.

- **Maryland.** On September 26, 2016, the Maryland Public Service Commission (PSC) initiated notice of a public conference reviewing key distribution systems aspects, including maximizing the advanced metering and associated infrastructure benefits to ratepayers; rate design, including time-varying rates; benefits and costs associated with the deployment of solar, and potentially other distributed energy resources (DER); appropriate classification and valuation of energy storage; DER interconnection, and distribution system planning.[41]

- **Massachusetts.** On August 19, 2015, National Grid submitted its grid modernization plan to the Massachusetts Department of Public Utilities (DPU).[42] The company's grid modernization plan considered four different scenarios, all varying in levels of impact to customers in terms of benefits and costs.[43] While the implementation of any of the four scenarios will achieve the elements of "advanced metering functionality" as required by the DPU,[44] the scenarios differ significantly in deployment of advanced meters. Two of the scenarios call for a full deployment of advanced meters to replace 1.3 million retail meters, while the others call for most customers to opt-in for advanced meter deployment.[45]

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

[41] *In the Matter of Transforming Maryland's Electric Distribution Systems to Ensure that Electric Service is Customer-Centered, Affordable, Reliable and Environmentally Sustainable in Maryland*, Notice of Public Conference, Public Conference 44, (Maryland PSC Sept. 26, 2016) *available at* http://www.psc.state.md.us/wp-content/uploads/PC-44-Notice-Transforming-Marylands-Electric-Distribution-System.pdf.

[42] Petition of Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid for Approval of its Grid Modernization Plan, Grid Modernization Plan, Grid Modernization Plan, DPU 15-120 (Massachusetts DPU Aug. 19, 2015), *available at* http://web1.env.state.ma.us/DPU/FileRoomAPI/api/Attachments/Get/?path=15-120%2fGrid_Mod_PlanFinalRedacted_Boo.pdf.

[43] *Id.* at 11.

[44] *Id.* at 36. As defined by the Massachusetts DPU, advanced metering functionality includes: (1) the collection of customers' interval usage data, in near real time, usable for settlement in the ISO-NE energy and ancillary services markets; (2) automated outage restoration and notification; (3) two-way communication between customers and the electric distribution company; and (4) communication with and control of a customer's appliances (with permission). *See* Investigation by the Department of Public Utilities on its own Motion into Modernization of the Electric Grid, D.P.U. 12-76-B, (Massachusetts DPU June 12, 2014), p. 11, *available at* http://www.mass.gov/eea/docs/dpu/electric/12-76-a-order.pdf.

[45] *Id.*

- **Michigan.** Consumers Energy expects to complete deployment of advanced meters[46] to all 1.8 million electricity customers by September 2017.[47] The company has been deploying advanced meters since August 2012.[48]

- **Minnesota.** On June 13, 2015, Governor Dayton signed a new law directing utilities to identify investments to modernize the transmission and distribution system by facilitating communication between the utility and its customers through the use of two-way meters, among other things.[49] As stated in a grid modernization report submitted by a Minnesota subsidiary of Xcel Energy, the utility is in the early stages of testing and field deployment of advanced meters in preparation for the expiration of their advanced meter reading (AMR)[50] meters.[51] The Minnesota Public Utilities Commission (PUC) is also engaged in a three-phased grid modernization initiative that started in November 2015.[52] As part of this initiative, the Minnesota PUC staff issued a report on grid modernization in March 2016,[53] and held a workshop on Integrated Distribution Planning Modernization in October 2016.[54]

[46] Consumers Energy, Upgraded Consumers Energy Meters Provide Michigan Homes, Businesses with Online Access to Energy Use Information, July 1, 2016, *available at* https://www.consumersenergy.com/News.aspx?id=8521&year=2016.

[47] In the Matter of the Application of Consumer Energy Company for Authority to Increase its Rates for the Generation and Distribution of Electricity and for Other Relief, Qualifications and Direct Testimony of Lauren Fromm, at 5, Case No. U-17990 (Michigan PSC July 22, 2016), *available at* https://efile.mpsc.state.mi.us/efile/docs/17990/0173.pdf.

[48] In the Matter, on the Commission's Own Motion, to Require Consumers Energy Company to Investigate and to Submit a Report to the Commission Regarding the Utility's Estimated Billing Practices, Estimated Billing Practices Staff Report, at 23, Case No. U-18002 (Michigan PSC May 18, 2016), *available at* https://efile.mpsc.state.mi.us/efile/docs/18002/0004.pdf.

[49] Minnesota State Legislature, House File 3 of the 2015 Special Session at ll. 76.24-76.31, approved on June 13, 2015, modifying Minn. Stat. §216B.2425, *available at* https://www.revisor.mn.gov/bills/text.php?number=HF0003&version=latest&session=89&session_number=1&session_year=2015.

[50] AMR meters "collect data for billing purposes only and transmit this data one way, usually from the customer to the distribution utility. Aggregated monthly kWh data captured on these meters may be retrieved by a variety of methods including drive-by vans with short-distance remote reading capabilities and communication over a fixed network such as a cellular network." EIA, Form EIA-861 Annual Electric Power Industry Report Instructions, Approval: OMB No. 1905-0129, Approval Expires: 05/31/2017, p. 17, *available at* https://www.eia.gov/survey/form/eia_861/instructions.pdf.

[51] In the Matter of the 2015 Minnesota Biennial Transmission Projects Report, 2015 Minnesota Biennial Transmission & Distribution Grid Modernization Report, at 11, Docket No. E999/M-15-439 (Minnesota PUC Oct. 30, 2015), *available at* https://www.xcelenergy.com/staticfiles/xe/PDF/Regulatory/MN-Filings-Biennial-Transmission-Grid-Modernization-Report.pdf.

[52] In the Matter of the Commission Investigation into Grid Modernization, Notice of Grid Modernization Stakeholder Meeting and Final Notice, Docket CI-15-556 (Minnesota PUC Nov. 18, 2015).

[53] In the Matter of the Commission Investigation into Grid Modernization, Staff Report on Grid Modernization, Docket CI-15-556 (Minnesota PUC March 2016), *available at* https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=eDocketsResult&docketYear=15&docketNumber=556#{E04F7495-01E6-49EA-965E-21E8F0DD2D2A}.

[54] In the Matter of the Commission Investigation into Grid Modernization, Notice of Grid Modernization Stakeholder Meeting and Final Notice, Notice of Integrated Distribution Planning Report and Stakeholder Workshop,(Minnesota PUC Sept. 13, 2016), *available at* https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7BBC

- **Missouri.** In 2015, Ameren Missouri completed installation of over 160,000 advanced meters in its service territory.[55] The company plans on investing a total of $360 million in smart grid infrastructure, including additional advanced metering from 2012-2021.[56]

- **New Hampshire.** On July 30, 2015, the New Hampshire Public Utilities Commission (PUC) initiated an investigation into grid modernization, including consideration of advanced meters.[57] On April 1, 2016, the New Hampshire PUC established a formal working group to, in part, "investigate the opportunities for different types of advanced meters and advanced metering options to provide the functionality needed to support grid modernization."[58]

- **North Carolina.** In response to a Duke Energy Carolinas' proposal to have customers who prefer to maintain or have reinstalled analog meters charged a one-time set-up fee of $150 and a monthly fee of $11.75 to cover the costs of manual meter reading,[59] the North Carolina Utilities Commission (NCUC) suspended the proposed charges on July 29, 2016, required the utility to answer specific NCUC questions on advanced meters, and set a timeline for interested party comments.[60] After Duke Energy Carolina responded to the NCUC's advanced metering questions, the North Carolina Attorney General's Office requested an extension of time for comments, which the NCUC granted.[61]

- **New York.** On March 17, 2016, the New York Public Service Commission (PSC) approved a plan by Consolidated Edison (ConEd), to distribute advanced meters to more than 3.2 million customers over a six-year period that starts in 2017.[62] As approved,

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E52F21-2497-4F2D-A70D-02614957A012%7D&documentTitle=20169-124836-01. Attached to this notice is a report prepared by ICF International on Integrated Distribution Planning.

[55] Ameren, 2015 Annual Report, Feb. 26, 2016, p. 2, *available at* https://www.ameren.com/-/media/corporate-site/Files/Reference/AmerenProxyMaterial/Ameren10K.pdf.

[56] *Id*. at 13.

[57] Investigation into Grid Modernization, Order of Notice: Electric Distribution Utilities, Docket No. IR 15-296 (New Hampshire PUC July 30, 2015), *available at* https://www.puc.nh.gov/Regulatory/Docketbk/2015/15-296/INITIAL%20FILING%20-%20PETITION/15-296%202015-07-30%20ORDER%20OF%20NOTICE.PDF.

[58] Investigation into Grid Modernization, Order on Scope and Process, Docket No. IR 15-296, Order No. 25,877 at 6, (New Hampshire PUC Apr. 1, 2016), *available at* https://www.puc.nh.gov/Regulatory/Docketbk/2015/15-296/ORDERS/15-296_2016-04-01_ORDER_25877.PDF.

[59] In the Matter of Application of Duke Energy Carolinas, LLC, for Approval of Advanced Metering Infrastructure Opt-Out Tariff, Duke Energy Carolinas, LLC's AMI Opt-Out Rider, Docket No. E-7, Sub 1115 (NCUC July 29, 2016), *available at* http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=992dc118-bf01-42e2-b0b6-964b14f1dfc1.

[60] *Id.*, Order Requesting Comments and Additional Information Regarding Proposed Smart Meter Opt-Out Charges, Docket No. E-7, Sub 1115 (NCUC Aug. 11, 2016), *available at* http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=43f8ec35-519e-4dd4-9c26-798ae4a9bbe4.

[61] *Id.*, Order Granting Extension of Time to File Reply Comments, Docket No. E-7, Sub 1115 (NCUC Nov. 16, 2016), *available at* http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=f9a1d816-bee1-488c-be33-305131b567d4.

[62] Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, Order Approving Advanced Metering Infrastructure Business Plan Subject to Conditions, CASE 15-E-0050, (New York PSC Mar. 17, 2016), *available at*

ConEd's Advanced Meter Infrastructure Business Plan includes 15-minute meter reads for residential customers, and five-minute reads for non-residential customers.[63] The New York PSC directed ConEd to develop a customer engagement plan, including data access and privacy policies, implementation of Green Button Connect My Data, one or more pilot projects, and opt-out tariffs.[64]

- **Oklahoma.** In mid-2016, Public Service Company of Oklahoma (PSO) completed the deployment of advanced meters across its service territory.[65] The Oklahoma Corporation Commission approved PSO's collection of revenues for the installation of the meters in April 2015.[66]

- **Pennsylvania.** In January 2016, Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company, and West Penn Power Company initiated full-scale deployment of advanced meters, and forecast installation of approximately 98.5 percent of all meters by mid-2019, and the remainder no later than 2022.[67]

- **Tennessee.** On December 1, 2015, the Memphis City Council approved Memphis Light, Gas and Water's (MLGW) full roll-out of advanced meters, projected for completion by 2020.[68] The deployment is the second phase of MLGW's two-phase plan to implement advanced meters, and is expected to cost $240 million.

- **Washington.** On January 6, 2016, the Washington Utilities and Transportation Commission declined to rule on the prudency of Avista Utilities' proposal for advanced meters.[69] The Commission stated that the issue was not ripe for Commission determination at the time, but that the company may file a separate accounting petition if Avista decides to go forward with its proposal.[70] Avista Utilities originally proposed a

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http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=15-E-0050&submit=Search.

[63] *Id*., ConEdison Advanced Metering Infrastructure Business Plan at 66 (New York PSC Oct. 15, 2015), a*vailable at* http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={6E51BC25-7CCB-446F-B6E0-F84A72880DAC}.

[64] *See supra* note 67.

[65] Jim Roth, Roth: PSO, AMI, and ROI, Journal Record, July 22, 2016, *available at* http://journalrecord.com/2016/07/22/roth-pso-ami-and-roi-opinion/.

[66] Application of Public Service Company of Oklahoma to be in Compliance with Order No. 591185, Issued in Cause No. PUD 201100106, Order No. 591186, Cause No. PUD 201300217, (OCC Apr. 14, 2015), *available at* http://imaging.occeweb.com/AP/CaseFiles/occ5114618.pdf.

[67] Joint Petition of Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company and West Penn Power Company for Approval of their Smart Meter Deployment Plans, 2015 Annual Progress Report Smart Meter Technology Procurement and Installation Plan, Docket Nos. 23411990, 2341994, 2341993, 2341991, (Pennsylvania PUC Aug. 3, 2015, *available a*t http://www.puc.pa.gov/pcdocs/1375241.pdf.

[68] MLGW, Smart Grid, *available at* http://www.mlgw.com/smart-grid.

[69] Washington Utilities and Transportation Commission v. Avista Corp, Final Order Rejecting Tariff Filing, Accepting Partial Settlement Stipulation, Authorizing Tariff Filings, Dockets UE-150204 and UG-150205, (Washington UTC Jan. 6, 2016), *available at* http://www.utc.wa.gov/_layouts/CasesPublicWebsite/GetDocument.ashx?docID=1862&year=2015&docketNumber=150204.

[70] *Id*. at 68-71.

six-year project to replace all retail meters with approximately 253,000 advanced meters.[71]

On July 25, 2016, Seattle City Light obtained approval from the Seattle City Council for an updated strategic plan for the years 2017-2022.[72] The company plans to invest $94 million[73] to replace approximately 430,000 retail meters with advanced meters, to be completed by the year 2019.[74]

[71] Washington Utilities and Transportation Commission v. Avista Corp, Direct Testimony of Don F. Kopczynski, Dockets UE-150204 and UG-150205, (Washington UTC Feb. 2015), *available at* http://www.utc.wa.gov/_layouts/CasesPublicWebsite/GetDocument.ashx?docID=114&year=2015&docketNumber=150204.

[72] Resolution 31678: A Resolution relating to the City Light Department; adopting a 2017-2022 Strategic Plan for the City Light Department and endorsing a six-year rate path required to support the Strategic Plan, Seattle City Council, July 25, 2016, *available at* http://seattle.legistar.com/LegislationDetail.aspx?ID=2769630&GUID=D312F4F5-868A-4989-8550-BCC7AA5E8343&FullText=1.

[73] Seattle City Light Strategic Plan Update 2017-2022, A Progress Report on the Future of Your Electric Service at 3, (2015), *available at* http://www.seattle.gov/light/stratplan/docs/strategic_plan_web.pdf.

[74] Seattle City Light Strategic Plan Update 2017-2022, Strategic Initiatives Summary at 7, (May 20, 2016), *available at* http://www.seattle.gov/light/stratplan/docs/2017-2022%20Strategic%20Initiatives%20Summary.pdf.

Chapter 3: Annual resource contribution of demand resources

Using the latest publicly available data, this chapter summarizes the annual resource contribution from retail and wholesale demand response programs on a national and regional basis from 2013 to 2014, and 2014 to 2015, respectively.[75] Table 3-1 presents data collected by EIA on 2013 and 2014 potential peak reduction from retail demand response programs within each of the eight regional electricity councils, as well as Alaska and Hawaii. Nationwide, total potential peak reduction[76] from retail demand response programs increased by 4,096 megawatts (MW), or 15.1 percent, between 2013 and 2014.

Table 3-1: Potential Peak Reduction (MW) from Retail Demand Response Programs by Region (2013 & 2014)

Region	Annual Potential Peak Reduction (MW)		Year-on-Year Change	
	2013	2014	MW	%
AK	27	27	0	0.0%
FRCC	1,924	3,389	1,466	76.2%
HI	35	41	6	16.5%
MRO	4,264	4,366	102	2.4%
NPCC	467	654	188	40.2%
RFC	5,362	5,006	-355	-6.6%
SERC	8,254	8,343	89	1.1%
SPP	1,594	1,324	-270	-16.9%
TRE	459	613	154	33.5%
WECC	4,681	7,427	2,745	58.6%
Unspecified	28	--	-28	-100.0%
Total	**27,095**	**31,191**	**4,096**	**15.1%**

Sources: EIA, EIA-861 Demand_Response_2013, Demand_Response_2014, Utility_Data_2013, and Utility_Data_2014 data files.

Note: Figures from source data are rounded to the nearest megawatt for publication. The percentage change is calculated based on the unrounded figures. Although some entities may operate in more than one NERC Region, EIA data have only one NERC region designation per entity. Commission staff has not independently verified the accuracy of EIA data.

Regionally, however, there were large differences in the change in potential peak reduction from 2013 to 2014. For example, Table 3-1 above indicates potential peak reduction increased in the WECC region by more than 2,700 MW compared to the previous year; this can be attributed primarily to a large increase in reported savings from commercial and industrial programs operated by Southern California Edison. Increased demand response potential in the FRCC region was largely due to greater reported savings from FPL's demand response programs, which

[75] The latest publicly available retail and wholesale data sets are used to determine the annual resource contributions from retail and wholesale demand response programs; these include EIA retail data for 2012 and 2013, as well as ISO/RTO wholesale data for 2014.

[76] *See Supra* note 3.

returned to a level last reported in 2012. These gains in demand response potential were offset by small drops in potential in other regions, such as RFC and Southwest Power Pool (SPP).

As Table 3-2 illustrates, in 2014, industrial customer demand response represented 16,505 MW, or 53 percent, of total potential peak reduction in retail programs, a decrease of two percentage points since 2013. Residential customer demand response accounted for 8,118 MW, or 26 percent, of total potential peak reduction from retail programs in 2014, the same percentage as the previous year. Demand response programs in the commercial sector accounted for 6,215 MW, or 20 percent, of total potential peak reduction, up approximately one percent from the previous year. The relative contribution by customer class varies by region. For example, residential demand response programs account for the largest portion of potential peak reduction in FRCC (approximately 49 percent) and MRO (approximately 44 percent). In contrast, commercial programs account for the majority of potential peak reduction in Alaska, Hawaii, NPCC and TRE; and industrial programs account for the majority in RFC, SERC, SPP, and WECC.

Table 3-2: Potential Peak Reduction (MW) from Retail Demand Response Programs by Region and Customer Class (2014)

Region	Customer Class				
	Residential	Commercial	Industrial	Transportation	All Classes
AK	5	13	9	0	27
FRCC	1,651	1,318	421	0	3,389
HI	15	26	0	0	41
MRO	1,930	818	1,618	0	4,366
NPCC	58	313	269	14	654
RFC	1,298	678	3,030	0	5,006
SERC	1,706	789	5,848	0	8,343
SPP	129	223	973	0	1,324
TRE	166	345	102	0	613
WECC	1,160	1,692	4,236	339	7,427
All Regions	**8,118**	**6,215**	**16,505**	**353**	**31,191**

Source: EIA, EIA-861 Demand_Response_2014 and Utility_Data_2014 data files.

Note: Figures from source data are rounded to the nearest megawatt for publication. Although some entities may operate in more than one NERC Region, EIA data have only one NERC region designation per entity. Commission staff has not independently verified the accuracy of EIA data.

Table 3-3 below presents potential peak reduction from wholesale demand response programs in 2014 and 2015. Across all ISO/RTO regions, potential peak reduction rose substantially in 2015 to 31,754 MW, a 10 percent increase from the previous year, outpacing peak demand growth of 4 percent. Therefore, the contribution of potential peak reduction to meeting peak demand increased to 6.6 percent in 2015, up from 6.2 percent in 2014.

Regionally, demand response participation increased in three of the seven ISOs/RTOs in 2015: PJM, NYISO and ISO-NE. Of these, the largest absolute and percentage increase in megawatts occurred in PJM, where demand response potential rose by 24 percent, or almost 2,500 MW. Most of this increase was due to significant new enrollment in PJM's load management products compared to 2014, particularly in the ComEd, ATSI, and AEP zones.[77] Potential peak reduction also increased in NYISO by 9 percent, or 114 MW, due to increased enrollment in the Special Case Resources program, a reliability demand response product. Similarly, potential peak reduction rose in ISO-NE by 8 percent, or 209 MW, due to increased enrollment in the Western/Central Massachusetts, Connecticut, and Northeastern Massachusetts zones. These increases in enrollments were offset by a fall in enrollment in the Maine zone, particularly in real-time demand response resources.[78]

In contrast, wholesale demand response potential fell in CAISO, by more than 150 MW, due to decreased enrollment in Southern California Edison's and Pacific Gas and Electric Company's price-responsive demand programs.[79] In addition, according to SPP, there has been no load-reducing demand response activity in its Integrated Marketplace since March 14, 2014. Potential peak reduction fell to zero in the region in 2015, a decrease from 48 MW in 2014.

[77] Based on comparison of data from *PJM 2014 Demand Response Operations Markets Activity Report* (Apr. 2015), pp. 6-8 and *PJM 2015 Demand Response Operations Markets Activity Report* (Jan. 2016), pp. 5-6.

[78] Based on comparison of data from "ISO-NE Demand Response Asset Enrollment," presented at Demand Resources Working Group Meeting (Jan. 7, 2015) (data as of Jan. 1, 2015), p. 2; and "ISO-NE Demand Resource Statistics," presented at Demand Resources Working Group Meeting (Jan. 20, 2016) (data as of Jan. 1, 2016), p. 2.

[79] CAISO, 2015 Annual Report on Market Issues and Performance, Table 1.4, p. 33 (May 2016).

Table 3-3: Potential Peak Reduction from U.S. ISO and RTO Demand Response Programs

RTO/ISO	2014 Potential Peak Reduction (MW)	2014 Percent of Peak Demand [8]	2015 Potential Peak Reduction (MW)	2015 Percent of Peak Demand [8]
California ISO (CAISO)	2,316 [1]	5.1%	2,160 [9]	4.4%
Electric Reliability Council of Texas (ERCOT)	2,100 [2]	3.2%	2,100 [10]	3.0%
ISO New England, Inc. (ISO-NE)	2,487 [3]	10.2%	2,696 [11]	11.0%
Midcontinent Independent System Operator (MISO)	10,356 [4]	9.0%	10,563 [12]	8.8 %
New York Independent System Operator (NYISO)	1,211 [5]	4.1%	1,325 [13]	4.3%
PJM Interconnection, LLC (PJM)	10,416 [6]	7.4%	12,910 [14]	9.0%
Southwest Power Pool, Inc. (SPP)	48 [7]	0.1%	0 [15]	0%
Total ISO/RTO	**28,934**	**6.2%**	**31,754**	**6.6%**

Sources:
[1] CAISO 2014 Annual Report on Market Issues & Performance, Table 1.3, p. 32 (June 2015)
[2] ERCOT Quick Facts (Dec. 2014)
[3] ISO-NE Demand Response Asset Enrollment, presented at Demand Resources Working Group Meeting (Jan. 7, 2015) (data as of Jan. 1, 2015), p. 2.
[4] 2014 State of the Market Report for the MISO Electricity Market (June 2015)
[5] 2014 Annual Report on Demand Side Management Programs of the New York Independent System Operator, Inc., ER01-3001 (Jan. 15, 2015), Table 1, p. 7
[6] PJM 2014 Demand Response Operations Markets Activity Report (Apr. 2015), pp. 3-5. Figure represents "unique MW."
[7] SPP Fast Facts (as of Dec. 31, 2014).
[8] Sources for peak demand data include: California ISO 2014 & 2015 Annual Reports on Market Issues and Performance; ERCOT 2014 & 2015 Demand and Energy Reports; ISO-NE Net Energy and Peak Load Report (Apr. 2015 & May 2016); 2014 & 2015 State of the Market Reports for the MISO Electricity Markets; 2014 & 2015 State of the Market Reports for the New York ISO Markets; 2014 & 2015 PJM State of the Markets Reports, Vol. 2; SPP Fast Facts (Feb. 2016).
[9] CAISO, 2015 Annual Report on Market Issues and Performance, Table 1.4, p. 33 (May 2016)
[10] ERCOT Quick Facts (Dec. 2015)
[11] ISO-NE Demand Resource Statistics, presented at Demand Resources Working Group Meeting (Jan. 20, 2016) (data as of Jan. 1, 2016), p. 2.
[12] 2015 State of the Market Report for the MISO Electricity Market (June 2015), Table 5, p. 76.
[13] 2015 Annual Report on Demand Side Management Programs of the New York Independent System Operator, Inc., ER01-3001 (Jan. 12, 2016), Attachment I, Table 1, p. 7
[14] PJM 2015 Demand Response Operations Markets Activity Report (Jan. 2016), pp. 3-4. Figure represents "unique MW."
[15] "[S]ince March 14, 2014, no load-reduction demand response activity has occurred in the Integrated Marketplace." *See* SPP Compliance Filing, Docket No. ER12-1179-024, p. 4 (May 24, 2016).

Note: Commission staff has not independently verified the accuracy of the RTO, ISO and Independent Market Monitor reports. Values from source data are rounded for publication.

Chapter 4: Potential for demand response as a quantifiable, reliable resource for regional planning purposes

The North American bulk power system is integrating an increasing level of demand response resources, variable energy resources, and distributed energy resources. As a result, NERC is considering how these resources can be reliably integrated into the operation and planning of the bulk power system,[80] and how these resources affect generation and load resources.[81] NERC asserts that demand response and price-responsive loads provide system operators with additional system-balancing tools.[82] To better understand and measure the performance of demand response resources, NERC developed and approved four new demand response metrics in 2015.[83] These new demand response metrics measure enrollment and event information to determine actual performance, including the resource's contribution to improved reliability. NERC states that future efforts intend to focus on improving data collection, maintaining data quality, and providing observations of possible demand response contributions to reliability.[84]

[80] NERC, State of Reliability Report, May 2016, p. 5, *available at* http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/2016_SOR_Report_Final_v1.pdf.

[81] NERC, Essential Reliability Services Task Force Measures Framework Report Nov. 2015, p. iv, *available at* http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Framework%20Report%20-%20Final.pdf.

[82] *Id*. at 63.

[83] NERC, State of Reliability Report, May 2016, pp. 70, 128.

[84] *Id.* at 123.

Chapter 5: Existing demand response programs and time-based rate programs and 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

This chapter provides information on demand response programs and time-based rate programs in 2013 and 2014, and summarizes recent federal, regional, state, and industry demand response actions. Tables 5-1 and 5-2 present customer enrollments in incentive-based[85] and time-based[86] demand response programs for 2013 and 2014, respectively. As shown in Table 5-1, from 2013 to 2014, the number of customers enrolled in incentive-based programs nationwide increased slightly to reach almost 9.3 million customers, after increasing by almost 70 percent in 2013 due to grants received under the American Recovery and Reinvestment Act of 2009's Smart Grid Investment Grants for the deployment of advanced meters and associated infrastructure.[87]

On a regional basis, customer enrollment increased by nearly 120 percent in TRE from 2013 to 2014, to reach more than three hundred thousand customers. EIA data indicates this is due to large increases in reported enrollments for programs run by Austin Energy, the City of San Antonio, TriEagle Energy, and CenterPoint Energy. Additionally, enrollment in incentive-based programs increased by 20 percent in SERC, due to increased enrollment in programs run by Snapping Shoals Electric Coop, Dominion, Duke, and Louisville Gas & Electric, and by 9 percent in RFC. Program enrollment fell in other regions, including WECC and NPCC, due to lower reported participation by Southern California Edison, PacificCorp, and ConEd, among others.

[85] Incentive-based demand response programs include direct load control, interruptible, demand bidding/buyback, emergency demand response, capacity market, and ancillary service market programs. *See* EIA, Form EIA-861 Instructions, Schedule 6-Part C.

[86] Time-based rate programs include real-time pricing, critical peak pricing, variable peak pricing, and time-of-use rates administered through a tariff. *See* EIA, Form EIA-861 Instructions, Schedule 6-Part C.

[87] U.S. DOE, "Recovery Act Selections For Smart Grid Investment Grant Awards – By State," updated November 2011, *available at* http://www.energy.gov/oe/downloads/recovery-act-selections-smart-grid-investment-grant-awards-state-updated-november-2011.

Table 5-1: Customer Enrollment in Incentive-based Demand Response Programs, by Region (2013 & 2014)

Region	Enrollment in Incentive-based Programs		Year-on-Year Change	
	2013	2014	Customers	%
AK	2,468	2,428	-40	-2%
FRCC	1,554,830	1,490,073	-64,757	-4%
HI	36,332	36,102	-230	-1%
MRO	1,248,723	1,227,445	-21,278	-2%
NPCC	62,631	51,227	-11,404	-18%
RFC	1,852,985	2,012,846	159,861	9%
SERC	1,084,449	1,303,339	218,890	20%
SPP	193,507	175,146	-18,361	-9%
TRE	138,613	302,913	164,300	119%
WECC	3,002,607	2,651,163	-351,444	-12%
Unspecified	10,205	12,947	2,742	27%
Total	**9,187,350**	**9,265,629**	**78,279**	**1%**

Sources: EIA, EIA-861 Demand_Response_2013, Utility_Data_2013, Demand_Response_2014, and Utility_Data_2014 data files.

Note: Although some entities may operate in more than one NERC Region, EIA data have only one NERC region designation per entity. Commission staff has not independently verified the accuracy of EIA data.

As Table 5-2 indicates, nationwide enrollment in time-based programs increased approximately 15 percent from 2013 to 2014. The bulk of this increase occurred in the RFC region with more than 575,000 new customer enrollments, and the WECC region, with over 270,000 new customer enrollments. The pace of new enrollments in 2014 fell well below the 60 percent increase experienced in 2013. EIA data indicates the increase in time-based program enrollments for the RFC region is largely due to a tripling of enrollment in an existing Baltimore Gas & Electric program. The increase in enrollment for the WECC region is primarily due to significant enrollment increases in commercial and industrial programs run by Southern California Edison. In TRE, enrollment increased significantly, from less than 1,000 to almost 50,000 customers, primarily as a result of TriEagle Energy residential program participation. Data within the table's "Unspecified" region also shows growth in time-based customer participation, reflecting an increase in residential time-based program enrollments for TXU Energy Retail and other retail power marketers.[88] Decreased enrollment in MRO and SERC reflect lower reported participation in programs run by Riverland Energy and Albertville Municipal Utilities Board, respectively.

[88] Power marketers are not required to specify a NERC region when responding to the EIA-861 survey. *See* EIA, Form EIA-861, Schedule 2, Part A, *available at* http://www.eia.gov/electricity/data/eia861/.

Table 5-2: Customer Enrollment in Time-based Demand Response Programs, by Region (2013 & 2014)

Region	Enrollment in Time-based Programs		Year-on-Year Change	
	2013	2014	Customers	%
AK	43	53	10	23%
FRCC	16,203	20,069	3,866	24%
HI	365	466	101	28%
MRO	108,527	94,176	-14,351	-13%
NPCC	258,426	252,323	-6,103	-2%
RFC	1,977,536	2,553,434	575,898	29%
SERC	236,662	203,954	-32,708	-14%
SPP	1,143,774	1,188,004	44,230	4%
TRE	968	49,481	48,513	5012%
WECC	2,146,548	2,416,960	270,412	13%
Unspecified	88,229	115,906	27,677	31%
Total	**5,977,281**	**6,894,826**	**917,545**	**15%**

Sources: EIA, EIA-861 Dynamic_Pricing_2013 and Dynamic_Pricing_2014 data files.
Note: Although some entities may operate in more than one NERC Region, EIA data have only one NERC region designation per entity. Commission staff has not independently verified the accuracy of EIA data.

FERC demand response orders and activities

On January 25, 2016, the U.S. Supreme Court issued its decision in *FERC v. EPSA.*[89] The *EPSA* decision reversed a May 2014 D.C. Circuit opinion holding that FERC's demand response regulation (Order No. 745) is *ultra vires* under the Federal Power Act (FPA) because it regulates retail sales, and that the demand response compensation directed in Order No. 745 was "arbitrary and capricious."[90] Instead, the U.S. Supreme Court found that the Commission had authority to adopt Order No. 745 under the FPA. The Court found that "the Rule governs a practice directly affecting wholesale electricity rates."[91] In addition, the Court upheld the Order No. 745 compensation approach. The Court found that the Commission "engaged in reasoned decision making", and that it "selected a compensation formula with adequate support in the record, and intelligibly explained the reasons for making that choice."[92]

In the last year, the Commission issued orders related to the participation of demand response in organized wholesale electric markets. The Commission had delayed action on several orders pending the Court's *EPSA* decision.[93]

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[89] 136 S. Ct. 760 (2016) ("*EPSA*").
[90] See *EPSA v. FERC*, 753 F.3d 216 (D.C. Cir. 2014).
[91] *EPSA* at 33-34.
[92] *Id*. at 33.
[93] For example, on April 21, 2016, the Commission issued five orders: Independent Market Monitor for PJM v. PJM Interconnection, L.L.C, 155 FERC ¶ 61,059 (2016), Viridity Energy, Inc. v. PJM Interconnection,

In addition to these orders, on June 3, 2016,[94] the Commission approved NYISO's proposed revisions to the measurement and verification of demand response facilitated by behind-the-meter resources that participate in NYISO's day-ahead economic demand response program. The proposed revisions included changes to the relevant definitions, new measurement and verification rules and baseline calculations, metering requirements, and data reporting requirements.

The Commission also issued two orders associated with proposals by CAISO that are designed to incorporate distributed energy resources (which include demand response) and facilitate energy storage. On June 2, 2016,[95] the Commission approved CAISO's distributed energy resource provider (DERP) proposal, subject to conditions. The DERP program establishes an initial framework to enable resources, such as demand response and storage, connected to distribution systems within CAISO's balancing authority area to form aggregations of 0.5 MW or more and participate in CAISO's energy and ancillary services markets. On August 16, 2016,[96] the Commission issued an order accepting two tariff revisions associated with CAISO's Energy Storage and Distributed Energy Resources initiative. The first revision allows non-generator resources, which may include energy storage resources, to submit their state-of-charge as a bid parameter in the day-ahead market and self-manage their state-of-charge and energy limits. Prior to this revision, CAISO set the state-of-charge level. The second revision establishes performance measurement methodologies that allow CAISO to determine the performance of behind-the-meter generator output. This revision will allow the behind-the-meter generator output, which may include energy storage resources, to be directly compensated for in the markets, and separates actions taken by these resources from facility demand response actions.

L.L.C., 155 FERC ¶ 61,060 (2016) , PJM Interconnection, L.L.C., 155 FERC ¶ 61,061 (2016), PJM Interconnection, L.L.C., 155 FERC ¶ 61,062 (2016) , and PJM Interconnection, L.L.C. 155 FERC ¶ 61,063 (2016).

[94] New York Independent System Operator, Inc., 155 FERC ¶ 61,243 (2016).

[95] California Independent System Operator Corporation, 155 FERC ¶ 61,229 (2016).

[96] California Independent System Operator Corporation, 156 FERC ¶ 61,110 (2016).

Other federal demand response activities

White House Council of Economic Advisers

In June 2016, the White House Council of Economic Advisers released a report entitled *Incorporating Renewables into the Electric Grid: Expanding Opportunities for Smart Markets and Energy Storage*[97] in conjunction with a White House event on the topic of scaling renewable energy and storage with advanced meters. The report discusses the ever-increasing value of grid management services – like demand response – in light of the growing penetration of renewable variable energy resources (VERs).[98] According to the report, the distinctive characteristics of renewable VERs highlight the importance of facilitating programs and technologies like demand response and energy storage to help manage steep generation ramping needs to meet net electricity load, known in California as the "duck curve".[99] The report examines in further detail four key value streams of demand response programs: (1) reduction of peak generation, thus lowering wholesale price spikes; (2) avoided transmission and distribution upgrades; (3) resource adequacy requirements; and (4) smoothing steep ramps in net load.[100] The report also highlights specific technologies and approaches for the expansion of demand response. Technologies such as smart meters can be used to increase the elasticity of electricity, smart appliances can automatically respond to price spikes, and vehicle-to-grid technology can work as another way to forego peak generation.[101] Additionally, models based on infrastructure as a service as opposed to the classic utility model and reforms to interconnection rules can enable demand response to participate more broadly.[102]

Energy Efficiency Improvement Act of 2015

On April 30, 2015, the Energy Efficiency Improvement Act of 2015 became law, enabling certain grid-enabled water heaters to participate in demand response programs.[103] According to the law, an electric resistance water heater previously deemed too inefficient to meet national appliance and equipment efficiency standards and commercially offered for sale alongside other water heating units,[104] is granted an exemption as long it has an energy factor of at least 1.061, is larger than 75 gallons, is grid-enabled, and is intended for participation in a demand response program.[105] Thirty-five states have utilities with water heater load control programs.[106]

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[97] The White House, *Incorporating Renewables into the Electric Grid: Expanding Opportunities for Smart Markets and Energy* Storage, White House Council of Economic Advisers, June 2016, *available at* https://www.whitehouse.gov/sites/default/files/page/files/20160616_cea_renewables_electricgrid.pdf.

[98] *Id.*

[99] *Id.*

[100] *Id.* at 28.

[101] *Id.* at 29.

[102] *Id.* at 30.

[103] Energy Efficiency Improvement Act of 2015, Pub. L. No. 114-11, 129 Stat. 182 (2015).

[104] 10 C.F.R. pt. 430.32(d) (2010).

[105] Energy Efficiency Improvement Act of 2015, Pub. L. No. 114-11, 129 Stat. 182 at 187 (2015).

[106] Katherine Tweed, Congress Passes Bill for Grid-Enabled Water Heaters, Greentech Media, April 22, 2015, a*vailable at* http://www.greentechmedia.com/articles/read/congress-comes-together-on-bill-for-grid-enabled-water-heaters.

U.S. Environmental Protection Agency: RICE Rule

In 2013, the U.S. Environmental Protection Agency (EPA) issued a final rule that modified the national emissions standards and the performance standards to allow backup reciprocating internal combustion engines (RICE), i.e., diesel generators, to operate without emissions controls for up to 100 hours per year as part of an emergency demand-response program.[107] On May 1, 2015, the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) reversed the RICE Rule.[108] In anticipation of an issuance of a mandate from the D.C. Circuit, on April 15, 2016, the EPA issued a guidance memorandum to explain how the EPA intends to implement the RICE Rule after issuance of the mandate.[109] The EPA's guidance stated that "it was EPA's view that this change will mean that an engine may not operate in circumstances described in the vacated provisions for any number of hours per year unless it is in compliance with the emission standards and other applicable requirements of a non-emergency engine." The EPA also stated that a prior 2010 regulation that allowed emergency engines is revoked. On May 4, 2016, the D.C. Circuit issued its mandate reversing and remanding the 2013 RICE Rule.[110]

As a result of the reversal of the RICE Rule, affected emergency generators can no longer operate when system operators, such as ISOs and RTOs, implement emergency procedures when there are inadequate operating reserves (i.e., NERC Emergency Action Alert 2), or participate in emergency demand response programs operated by system operators. These affected generators can only operate when their host facilities lose off-site power. Therefore, as of May 4, 2016, emergency generators can no longer operate unless they are retrofitted to comply with the EPA's national emissions standards.

U.S. Department of Defense

The U.S. Department of Defense (DOD) accounts for the most energy consumed by any agency of the federal government.[111] The DOD's Defense Logistics Agency Energy (DLA Energy) provides logistics, acquisition, and technical service assistance to DOD and other government agencies on a wide range of energy needs including participation in demand-response programs.[112] For fiscal year 2015, DOD's DLA Energy reports that 80 separate demand response programs were undertaken by DOD and DOD-supported federal civilian agencies, which are located across 15 states and the District of Columbia, totaling more than 236.6 MW,

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[107] *See* National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines, 78 Fed. Reg. 6,674 (Jan. 20, 2013) ("RICE Rule").

[108] See *Del. Dep't of Nat. Res. and Envtl. Control v. EPA*, No. 13-1093 (D.C. Cir. May 1, 2015)).

[109] U.S. EPA, Office of Air Quality and Standards, Guidance on Vacatur of RICE NESHAP and NSPS Provisions for Emergency Engines, April 15, 2016, *available at* https://www3.epa.gov/ttn/atw/icengines/docs/RICEVacaturGuidance041516.pdf.

[110] Mandate Effectuating the Vacatur in *Delaware v. EPA*, 785 F. 3d 1 (D.C. Cir. 2015), issued on May 4, 2016.

[111] U.S. DOE, "Defense Department energy use falls to lowest level since at least 1975," February 4, 2015, *available at* http://www.eia.gov/todayinenergy/detail.cfm?id=19871.

[112] U.S. DOD, Defense Logistics Agency Energy, Fiscal Year 2015 Fact Book, pp. 2, 12, a*vailable at* http://www.dla.mil/Portals/104/Documents/Energy/Publications/E_Fiscal2015FactBookLowResolution_160707.pdf?ver=2016-07-08-124636-630.

and netting $3.2 million in savings for the year.[113] DLA Energy advises that additional savings will continue to be realized on military installations and federal civilian agencies during fiscal year 2016 through demand response programs. Additional participation in demand response programs may occur due to updated DOD installation energy management procedures issued on March 16, 2016. These new procedures will ensure that DOD entities comport with the requirements of Executive Order 13693,[114] and will facilitate DOD's review of peak shaving and demand response opportunities when taking steps to ensure energy resilience.[115] Additionally, DOD's environmental research programs note that DOD facilities primarily participate in demand response programs that require a manual response to email or phone notifications instead of employing an automated response, which limit demand response program participation to next day or four-hour-notice programs.[116] Consequently, one of the demonstration projects being funded documents and validates improved performance and cost savings by participating in automated, fast response demand response programs.[117]

U.S. General Services Administration

The U.S. General Services Administration (GSA) manages 376.9 million square feet of building space across over 9,600 buildings,[118] and relies on demand response programs to help meet energy needs.[119] In June 2016, GSA reported that its demand response participation in NYISO and PJM programs resulted in $1.6 million in rebates, which were in turn used to fund additional energy and water saving projects.[120] GSA continues efforts to employ advanced meters and data analytics, including an examination of commercial off-the-shelf products to support "smart building solutions" that include smaller building systems, improved user interfaces, reduced response times, green technologies, and demand response.[121] Additionally, in October 2016, GSA issued a Request for Information to further examine building-level energy storage to

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[113] *Id.* at 52.

[114] On March 19, 2015 President Obama signed Executive Order 13693: Planning for Federal Sustainability in the Next Decade, which directs federal agencies to increase efficiency and improve environmental performance. Executive Order 13693 3 C.F.R, pp 15871-15884 (2015), *available at* http://www.gpo.gov/fdsys/pkg/FR- 2015-03-25/pdf/2015-07016.pdf.

[115] U.S. DOD, Department of Defense Instructions, Number 4170.11, December 11, 209, Change 1, Effective March 16, 2016, Subject: Installation Energy Management, [Procedure 3.b.(1)(c)], pp. 17-18, *available at* http://www.dtic.mil/whs/directives/corres/pdf/417011p.pdf.

[116] U.S. DOD, Strategic Environmental Research and Development Program (SERDP) Environmental Security Technology Certification Program (ESTCP), Demonstrating Secure Demand Response in DOD, *available at* https://www.serdp-estcp.org/News-and-Events/Blog/Demonstrating-Secure-Demand-Response-in-DoD.

117 DOD SERDP and ESTCP, Market Aware High Performance Buildings Participating in Fast Load Response Utility Programs with a Single Open Standard Methodology (EW-201401), *available at* https://www.serdp-estcp.org/Program-Areas/Energy-and-Water/Energy/Conservation-and-Efficiency/EW-201401.

[118] U.S. GSA, Public Buildings Service, *available at* http://www.gsa.gov/portal/content/104444.

[119] U.S. GSA, 2015 Strategic Sustainability Performance Plan, July 9, 2015, *available at* http://www.gsa.gov/portal/mediaId/119682/fileName/GSA_FY_2015_SSPP_Final.action.

[120] U.S. GSA, "GSA's Northeast and Caribbean Region Reaches $1.6 Million Mark in Demand Response Rebate," The GSA Bog, June 15, 2016, *available at* https://gsablogs.gsa.gov/gsablog/2016/06/15/region-2-reaches-1-6-million-mark-in-demand-response-rebate/

[121] Mark Ewing (Energy Division Director, GSA National Office), Strategic Vision for GSA Energy, August 2015, p. 16, *available at* http://energy.gov/sites/prod/files/2015/08/f25/T1S1_Ewing.pptx.

facilitate demand response, enhance resiliency, and explore potential replacement of emergency back-up generation units.[122]

U.S. Department of Veteran's Affairs

The U.S. Department of Veteran's Affairs (VA) is the federal government's largest civilian agency with 1,897 facilities[123] totaling 151.5 million gross square feet.[124] The VA's Sustainable Design Manual incorporated demand response programs as a site option,[125] and, in addressing the Executive Order 13693 requirements, continues to evaluate the appropriateness of demand response in different types of existing buildings.[126]

State legislative and regulatory activities related to demand response

This section highlights developments in retail demand response and time-based pricing activities. States continue to use demand response as an important resource, including the use of demand response to meet state policy goals related to modernization of the grid and the electric industry, and are increasingly looking towards new technologies to facilitate demand response.

- **California.** In April 2016, Lawrence Berkeley National Laboratory (LBNL) released Phase I of a study for the California Public Utilities Commission (PUC) on the topic of leveraging smart meter data to estimate the potential for demand response and advanced behind-the-meter storage to provide cost-effective resources as part of California's future electricity system.[127] The LBNL Phase 2 report will explore the potential for demand response and distributed energy resources to meet capacity, ancillary services, ramping, and flexibility needs in California.[128]

  On June 9, 2016, the California PUC approved proposals from the state's three investor-owned utilities (IOUs) for 2017 demand response programs and activities. The California PUC approved $59.9 million for Pacific Gas and Electric Company, $23.8 million for San Diego Gas & Electric (SDG&E), and $56.28 million for Southern

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[122] GSA, Request for Information (RFI) to obtain information on energy storage systems in order to assist GSA in evaluating the feasibility of energy storage systems in various locations, October 31, 2016, Solicitation Number: GS-00P-17-BSD-1232, *available at* https://www.fbo.gov/index?s=opportunity&mode=form&id=910181950d158c022391072c502461c0&tab=core&_cview=1

[123] U.S. Department of Veteran's Affairs (DVA), Locations, *available at* http://www.va.gov/directory/guide/home.asp.

[124] U.S. DVA, 2015 Strategic Sustainability Performance Plan, p. 2, *available at* http://www.green.va.gov/docs/2015VAsspp.pdf.

[125] U.S. DVA, Office of Construction & Facilities Management, Sustainable Design Manual, *available at* http://www.cfm.va.gov/til/sustain/dmSustain.pdf.

[126] U.S. DVA, 2015 Strategic Sustainability Performance Plan, p. 40.

[127] LBNL, 2015 California Demand Response Potential Study: Charting California's Demand Response Future, Interim Report on Phase 1 Results, April 1, 2016, *available at* http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=10632.

[128] *Id.* at 3.

California Edison.[129] The California PUC also adopted a separate $11.8 million proposal by Southern California Edison to continue its Demand Bidding Program to help alleviate the effects of the natural gas leak at Southern California Gas Company's Aliso Canyon Storage Facility.[130]

As part of an effort to bifurcate utility demand response programs into demand- and supply-side resources and then integrate demand response resources into the California Independent System Operator's (CAISO) markets by 2018, the California PUC established a Demand Response Auction Mechanism (DRAM) pilot for third parties to provide demand response outside of utility programs. During the pilot, the IOUs and third parties offer portions of their own demand response portfolios into the CAISO market. The first deliverables of this program started on June 1, 2016, and the IOUs are currently in the process of selecting bids.[131] The California PUC has also authorized Automated Demand Response Programs that provide incentives to customers who invest in technologies (such as energy management systems) that automate load reduction in response to a signal from a utility or third-party demand response provider. As a condition of receiving these incentives, the customer is required to remain in the demand response program for at least three years. Participants receive 60 percent of the total program incentive after installation of the equipment and the remaining 40 percent upon verification of performance during a full demand response season.[132]

Also, with the permanent retirement of the San Onofre Nuclear generation station, SDG&E is seeking offers for up to 140 MW of new "preferred energy resources", including demand response, distributed generation, energy efficiency, energy storage, and renewable energy to meet local capacity requirements.[133] After receiving and evaluating offers, SDG&E expects to submit its selected agreements to the California PUC for approval in early- to mid-2017.[134]

- **Colorado.** In 2015, Public Service Company of Colorado (PSCo) offered three types of demand response products (direct load control, interruptible demand response, and non-dispatchable demand response) and realized 10.5 MW largely through PSCo's residential air conditioning program.[135] PSCo is also offering a building optimization software

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[129] Order Instituting Rulemaking to Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements, Rulemaking 13-09-011, Decision 16-06-029 (California PUC June 9, 2016), *available at* http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M163/K467/163467479.PDF.

[130] *Id*.

[131] California PUC, California Smart Grid: Annual Report to the Governor and Legislature, January 1, 2016, p. 12, *available at* http://www.cpuc.ca.gov/uploadedFiles/CPUC_Website/Content/Utilities_and_Industries/Energy/Reports_and_White_Papers/2015SmartGridAnnualReport.pdf.

[132] *Id.* at 13.

[133] SDG&E, SDG&E 2016 Preferred Resources Local Capacity Requirement Request for Offers, *available at* http://www.sdge.com/procurement/2016PrefResourcesLCRRFO.

[134] *Id.*

[135] Xcel Energy, Demand-Side Management Annual Status Report Electric and Natural Gas Public Service Company of Colorado March 30, 2016, Proceeding No. 14A-1057EG, p. 85, *available at*

evaluation pilot, and separately noted the impacts of new EPA back-up generator emission rules upon customer participation.[136]

On September 18, 2015, Black Hills/Colorado Electric Utility Company (Black Hills) and settling parties submitted a settlement agreement regarding Black Hills' electric demand side management plan for 2016-2018.[137] On December 8, 2015, the settlement agreement, which includes a proposal to develop a residential and/or small commercial pilot focused on studying demand response potential as well as energy savings from adoption of smart thermostats,[138] was recommended for approval by the assigned administrative law judge.[139]

- **Hawaii.** On December 30, 2015, the Hawaiian Electric Company (HECO) and its subsidiaries, submitted an interim Demand Response Portfolio proposal to the Hawaii PUC.[140] Developed in accordance with HECO's Integrated Demand Response Portfolio Plan (IDRPP),[141] the proposal provides for a portfolio of demand response program tariffs as well as a reporting schedule and associated cost recovery. On April 1, 2016, HECO also submitted its Power Supply Improvement Plan Update to the Hawaii PUC,[142] which includes a proposal to implement a demand response management system to provide customers with more options and to increase integration of rooftop solar. HECO also intends to implement demand response management system software by mid-2017 that will serve as the platform for the consolidated demand response programs and leverage distributed energy resources.[143]

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https://www.xcelenergy.com/staticfiles/xe-responsive/Admin/Managed%20Documents%20&%20PDFs/2015-CO-DSM-Annual-Status-Report.pdf.

136 *Id*. at 85-86.

137 In the Matter of the Application of Black Hills/Colorado Electric Utility Company, LP for Approval of Its Electric Demand Side Management (DSM) Plan for Program Years 2016-2018 and for Approval of Revisions to Its Electric DSM Cost Adjustment Tariff, Proceeding No. 15A-042E, Decision No. R15-1292, (Colorado PUC, Dec. 8, 2015), *available at* https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=603724&p_session_id=.

138 *Id*. at 28.

139 In the Matter of the Application of Black Hills/Colorado Electric Utility Company, LP for Approval of Its Electric Demand Side Management (DSM) Plan for Program Years 2016-2018 and for Approval of Revisions to Its Electric DSM Cost Adjustment Tariff, Settlement Agreement, Proceeding No. 15A-042E (Colorado PUC, Sept. 18, 2015).

140 For Approval of Demand Response Program Portfolio Tariff Structure, Reporting Schedule, and Cost Recovery of Program Costs through the Demand-Side Management Surcharge, Docket No. 2015-0412, (Hawaii PUC Dec. 30, 2015).

141 In November of 2015, HECO filed its revised IDRPP, along with a consolidated demand response program application. *See* Integrated Demand Response Portfolio Plan, Supplement: System Response Requirements (Revised), Docket No. 2007-0341, (Hawaii PUC Nov. 20, 2015).

142 Instituting a Proceeding to Review the Power Supply Improvement Plans for Hawaiian Electric Company, Inc., Hawaiian Electric Light Company, Inc., and Maui Electric Company, Limited, Docket No. 2014-0183, (Hawaii PUC Apr. 1, 2016).

143 Application for Approval to Defer Certain Computer Software Development Costs or a Demand response Management System, to Accumulate an Allowance for Funds Used During Construction, Etc., Docket No. 2015-0411, (Hawaii PUC Dec. 30, 2015).

- **Idaho.** In March 2016, Idaho Power reported successful operation of all three of its demand response programs for 2015.[144] The company realized a total demand reduction of 367 MW from 385 MW of enrolled capacity.[145]

- **Illinois.** In October 2015, Chicago and Cook County initiated participation in the Combined Capacity Asset Performance Project (CCAP) pilot in collaboration with the Environmental Defense Fund and PJM Interconnection.[146] Phase I of the pilot project combines variable renewable energy resources, distributed energy resources and the demand response potential of 60 buildings into combined capacity performance assets that are then bid into the PJM capacity market.[147] Phase II will evaluate the inclusion of residential buildings using controllable thermostats to create a year-round resource.[148]

  In December 2015, ComEd partnered with MeterGenius to launch a six-month pilot program in which a selection of customers are given access to mobile software that allows them to budget and track their energy use by the hour, day, week, or month, and also receive monthly communications with customized energy-saving tips. Customers enrolled in the pilot program participate in energy reduction competitions and earn points redeemable for gift cards or other energy efficient products.[149] The pilot is one of several efforts undertaken through ComEd's "SmartGridExchange" initiative, which is designed to bring new energy management options to customers and has been developed through third-party and university partnerships.[150]

- **Massachusetts.** On January 28, 2016, Massachusetts Department of Public Utilities (DPU) approved state utilities' 2016-2018 Three Year Energy Efficiency Plans, which included early efforts to develop new demand response strategies.[151] Two utilities, Cape Light Compact and National Grid, proposed specific demand response demonstration projects, and both utilities will explore electric vehicle charging during off-peak times as a demand response strategy. The Massachusetts Energy Efficiency Advisory Council,

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[144] Idaho Power, Annual Demand Side Management 2015 Report, *available at* https://www.idahopower.com/EnergyEfficiency/reports.cfm. *Note* The Idaho Power service area includes portions of eastern Oregon, and the annual report aggregates data for the two states. Idaho Power's Oregon-based demand response programs are approved by the Public Utility Commission of Oregon and funded via the Oregon Rider.

[145] *Id.* at 8.

[146] Environmental Defense Fund, Groups Launch Pilot to Demonstrate New Approaches for Demand Response in Chicago, October 6, 2015, *available at* https://www.edf.org/media/groups-launch-pilot-demonstrate-new-approaches-demand-response-chicago.

[147] Andrew Barbeau, Accelerate Group, *Combined Capacity Asset Performance Project*, PJM Seasonal Capacity Resources Senior Task Force presentation, June 6, 2016, p. 4, *available at* http://www.pjm.com/~/media/committees-groups/task-forces/scrstf/20160606/20160606-item-02-combined-capacity-asset-performance.ashx.

[148] *Id*.

[149] News Release, Commonwealth Edison Company (ComEd), ComEd and Technology Start-Up MeterGenius Join Forces to Help Customers Save Energy and Money (Dec.17, 2015), *available at* https://www.comed.com/News/Documents/newsroomreleases_12172015.pdf.

[150] *Id*.

[151] Three-Year Plans 2016-2018, D.P.U. Docket Nos 15-160 through D.P.U. 15-169, 2016-2018 Three-Year Energy Efficiency Plans Order, p. 134, (Massachusetts DPU Jan. 28, 2016), *available at* http://www.mass.gov/eea/docs/dpu/energy-efficiency-three-year-plans-order-1-28-16.pdf

which is charged with reviewing required statewide electric and gas energy efficiency plans prepared by the state's utilities, has identified demand response as a priority for 2016 through 2018,[152] and Massachusetts utilities are participating in a demand savings group to evaluate potential demand response strategies.[153]

- **Michigan.** In November 2015, Consumers Energy Company filed an application with the Michigan Public Service Commission (PSC) seeking authority to adjust its rate design and other tariff related issues. Under Consumers Energy's current pilot direct load management tariff, the company is permitted to cycle participants' air conditioning off only during certain peak times of the day.[154] Consumers Energy proposed to remove the time limits and allow cycling at any time. In November 2015, the Michigan PSC found that the pilot direct load management tariff should be adjusted to authorize curtailment during off-peak hours, but only if directed by the regional grid operator in an emergency.[155]

  Consumers Energy also requested that the limit on callable peak event days under its dynamic peak pricing (DPP) tariff be removed. The current tariff allows for a maximum of eight peak event days annually. Consumers Energy argued that limiting the peak days could result in the disqualification of the DPP program as a load managing resource (LMR) under MISO's program. The Michigan PSC denied this request recognizing that "there may need to be some changes to existing retail tariffs to align with wholesale rules, but that there may also be opportunities to shape wholesale rules to accommodate different demand response products at the retail level."[156] The Michigan PSC held that a change in the number of event days in the year is not necessary at this time, and directed Consumers Energy to provide more complete evidence of MISO's LMR requirements if it wishes to make changes in the future.

- **New York.** In August 2016, ConEd held its first demand response auction as part of the Brooklyn Queens Neighborhood Program resulting in 10 offers being accepted for 22 MW of demand response by 2018.[157] ConEd undertook the effort to defer the construction of a $1.2 billion substation, and agreed to pay the demand response providers amounts ranging from $215 to $988 per kilowatt per year.

  As part of Reforming the Energy Vision initiative, National Grid's July 1, 2016 Initial Filing to the New York PSC for the Demand Reduction Demonstration Project in the town of Clifton Park proposes to install advanced meters, which will provide customers access to near real-time data about their electric consumption, allow valuation of demand

[152] *Id.* at 134.
[153] *Id.* at 26.
[154] In the Matter of the Application of Consumers Energy Company for Authority to Increase its Rates for the Generation and Distribution of Electricity and for Other Relief, Case No. U-17735, (Michigan PSC Nov. 19, 2015), *available at* http://www.dleg.state.mi.us/mpsc/orders/electric/2015/u-17735_11-19-2015.pdf.
[155] *Id.* at 101.
[156] *Id.* at 100.
[157] New Release, Con Edison Takes New Approach To Rewarding Customers for Smart Usage, August 5, 2016, *available at* https://www.coned.com/newsroom/news/pr20160805.asp.

response and capacity payments to residential customers, as well enable price signal services such as peak time rewards and time-of-use and demand rates.[158]

- **Oregon.** On March 8, 2016, Oregon enrolled comprehensive electric legislation requiring, in part, that, electric companies, as directed by the Oregon PUC, plan for and pursue acquisition of cost-effective demand response resources.[159] Oregon PUC staff held an April 21, 2016 workshop with stakeholders and presented a preliminary implementation timeline, with demand response programs potentially being considered in the third quarter of 2017.[160]

  On April 28, 2016, Portland General Electric (PGE) reported favorable results on the company's latest Automated Demand Response (ADR) pilot program to the Oregon PUC, stating that it learned a tremendous amount about the marketing of demand response to large customers and the ability of an ADR program to help cost-effectively meet capacity needs on peak days.[161] PGE requested a one-year extension of the ADR pilot program, and if results are again favorable, to treat the ADR program in a manner similar to other power cost and capacity resources.[162]

- **Rhode Island.** In its 2016 System Reliability Procurement Report, National Grid proposes to continue its ongoing load curtailment pilot program and is seeking enough customers to provide 1 MW of load reduction by the end of 2017. If the program is successful in demonstrating sustained load relief over the six-year pilot period from 2012-2017, the pilot program will defer construction of a new substation feeder estimated to cost $2.93 million. To increase participation in the remaining two years of the project, National Grid proposes to continue all incentives offered in 2015, and to begin offering a limited number of wi-fi thermostats to customers directly and with a reduced customer co-pay, rather than through the previous mail-in rebate program.[163] National Grid intends to install 51 kW of planned demand response capacity in 2016.[164] National Grid also

[158] Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Case No. 14-M-0101, National Grid Proposed REV Demonstration Project Filing (New York PSC July 1, 2016), pp. 7-12, *available at* http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BDE450E2B-D82F-4046-8B79-BEAD03927CAB%7D.

[159] Oregon State Legislature, 2016 Legislative Session Information, Senate Bill 1547 Enrolled Elimination of Coal from Electric Supply, *available at* https://olis.leg.state.or.us/liz/2016R1/Downloads/MeasureDocument/SB1547/Enrolled

[160] Derek Green, Oregon PUC outlines ambitious schedule for implementation of Clean Electricity programs, Davis Wright Tremaine LLP Energy & Environmental Law Blog, April 25, 2016, *available at* http://www.energyenvironmentallaw.com/2016/04/25/oregon-puc-outlines-ambitious-schedule-for-implementation-of-clean-electricity-programs/

[161] In the Matter of Portland General Electric Company's Automated Demand Response Interim Report, Docket No. RE 126, UM 1514 PGE/Second Automated Demand Response Interim Report RE 126 (5), (Oregon PUC Apr. 28, 2016), *available at* http://edocs.puc.state.or.us/efdocs/HAQ/re126haq111649.pdf

[162] *Id*.

[163] The Narragansett Electric Company, d/b/a National Grid 2016 System Reliability Procurement Report, Docket No. 458, National Grid 2016 System Reliability Procurement Report, (Rhode Island PUC Oct. 15, 2015), *available at* http://www.ripuc.org/eventsactions/docket/4581-NGrid-2016-SRP(10-14-15).pdf.

[164] *Id.*, National Grid Presentation to the Rhode Island Public Utilities Commission, Dec. 2, 2015, *available at* http://www.ripuc.ri.gov/eventsactions/docket/4581-NGrid-Presentation(12-2-15).pdf.

reports that 85 percent of the planned demand response assumption was met during demand response events in 2015.

The State of Rhode Island is also seeking assistance in identifying state-owned and other facilities eligible to provide demand response capabilities that can be enrolled in the ISO New England forward capacity market.[165]

[165] State of Rhode Island Department of Administration Division of Purchases, Request for Proposal (RFP) # 7550564 TITLE: Demand Response Services, April 21, 2015, *available at* http://www.purchasing.ri.gov/RIVIP/StateAgencyBids/7550564.pdf.

Chapter 6: Regulatory barriers to improved customer participation in demand response, peak reduction, and critical period pricing programs

The 2009 National Assessment of Demand Response Potential[166] and previous annual reports describe the barriers to customer participation in demand response. The federal government and state and local governments continue to address outstanding barriers to demand response. Recent actions are presented below.

- **Implementing Time-based Pricing.** As previously reported, several state commissions (e.g., California PUC and the Massachusetts DPU) have begun to take action to introduce time-based rate structures for their customers. In the past year, an additional driver for the deployment of time-based rates gained momentum – state net energy metering policies. Time-based pricing for customers with rooftop solar panels is being offered as a compromise to resolve conflicts over state net energy metering policies. For example, in January 2016, the California PUC issued its decision on net energy metering.[167] According to the new policy, net-metered California solar customers will be required to move to time-of-use (TOU) rates that charge different prices during different times of the day. More recently, Xcel Energy and Colorado solar interests filed a compromise in August 2016 in the utility's general rate case that would avoid new grid fees, prevent cuts in payments to solar owners, and institute TOU rates, among other changes.[168]

- **Lack of Additional Market Opportunities.** As previous FERC staff assessments have found, the vast majority of demand response programs were implemented by electric utilities and balancing authorities, such as ISOs and RTOs, to act as emergency resources or to provide opportunities for demand response to directly participate in retail and wholesale markets. Other opportunities for monetizing demand response were in the minority and generally lacking. This dynamic is starting to change and additional market opportunities are beginning to be created for demand response to provide additional value. The use of demand response to provide distribution-level benefits and deferral of infrastructure continues in New York. ConEd held its first auction for demand response capacity under its Brooklyn-Queens Neighborhood Project, which seeks to cut customer usage to defer a substation investment. In August 2016, ConEd accepted offers for 22 MW of demand reductions from 10 providers.[169] Utilities, such as HECO, are utilizing

[166] FERC, A National Assessment of Demand Response Potential, June 2009, *available at* http://www.ferc.gov/legal/staff-reports/06-09-demand-response.pdf.

[167] Decision Adopting Successor to Net Energy Metering Tariff, Decision 16-01-044, January 28, 2016 Rulemaking 14-07-002, (California PUC Jan 28, 2016), *available at* http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M158/K181/158181678.pdf.

[168] In the Matter of the Application of Public Service Company of Colorado for Approval of Its Solar Connect Program, Proceeding No. 16A-0055E, Joint Motion to Consolidate Proceedings, Approve Non-Unanimous Comprehensive Settlement Agreement, Adopt Procedures, and Unopposed Request for Shortened Response Time at 12, *available at* https://www.dora.state.co.us/pls/efi/EFI.Show_Filing?p_fil=G_678021&p_session_id=.

[169] *See supra* note 169.

demand response programs as a means to support the integration of distributed energy resources. New smart devices, such as the Nest smart thermostat, are being increasingly integrated into utility demand response programs. Nest recently announced a deal with Southern California Edison to sign up 50,000 of the utility's customers to a Rush Hour Rewards program designed to adjust thermostat setting to reduce 50 MW of demand. Southern California Edison's customers can receive a bill credit of as much as $125 for participating.[170]

- **Coordination of Federal and State Policies.** A lack of coordination among policies at the federal and state levels could slow the development of demand response resources. While additional coordination is warranted, progress continues to occur. For example, as discussed above, the California PUC established the DRAM pilot to include demand response in the CAISO market. The California PUC's goal is to integrate all supply-side demand into CAISO wholesale markets by 2018.[171]

[170] Nest, Get paid up to $125 without lifting a finger, *available at* https://nest.com/energy-partners/southern-california-edison/.

[171] *See Supra* note 141.

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