*Assessment of*

# Demand Response AND Advanced Metering

*Federal Energy Regulatory Commission* *Staff Report*

*December 2017*

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## Staff Report

## Federal Energy Regulatory Commission

**December 2017**

**The opinions and views expressed in this staff report do not necessarily represent those of the Federal Energy Regulatory Commission, its Chairman, or individual Commissioners, and are not binding on the Commission.**

# 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 2017**

## Chapter 1: Introduction

This report is the Federal Energy Regulatory Commission staff's (FERC or Commission staff's) twelfth annual report on demand response and advanced metering required by section 1252(e)(3) of the 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 in the United States. According to the Energy Information Administration (EIA),[2] 64.7 million advanced meters were operational nationwide in 2015 out of a total of 150.8 million meters, indicating a 42.9 percent penetration rate;
- Over the past year, a number of state regulatory bodies have undertaken or are continuing broad grid modernization efforts, some of which include large-scale deployment of advanced meters. In addition, there has been movement towards further deployment of time-of-use rates in several states.
- In the organized wholesale markets, the contribution of demand resources to meeting peak demand decreased to 5.7 percent in 2016 from 6.6 percent in 2015;
- The North American Electric Reliability Corporation (NERC) notes that the bulk power system is integrating more demand response resources, as well as other distributed and renewable energy resources. In addition to collecting and presenting reliability demand response data and results, NERC continues its efforts to integrate economic demand response within the Demand Response Availability System (DADS) database;
- The North American Energy Standards Board (NAESB) ratified two new books of retail demand response business standards, and is expected to complete new Open Field Message Bus (OpenFMB) cyber-security model business standards in 2017.

[1] As defined by the U.S. Energy Information Administration (EIA), Advanced Metering Infrastructure (AMI) Meters (also referred to throughout this report as "advanced 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, http://www.eia.gov/survey/form/eia_861/instructions.pdf.

[2] EIA, Form EIA-861 Advanced_Meters_2015 data file (re-released November 1, 2016).

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).

# Chapter 2: Saturation and penetration rate of advanced meters

This chapter reports on penetration rates for advanced meters, and developments related to grid modernization and advanced metering. As summarized in Table 2-1 and noted in previous staff reports, 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**

| Source | Data As Of | Number of Advanced Meters (millions) | Total Number of Meters (millions) | Advanced Meter Penetration Rate (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 | 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 | 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% |
| 2015 Form EIA-861 | Dec 2015 | 64.7 [11] | 150.8 [11] | 42.9% |
| Institute for Electric Innovation | Dec 2015 | 65.6 [12] | 150.8 [11] | 43.5% |

*Sources:*
[1] FERC, *Assessment of Demand Response and Advanced Metering staff report* (2008).
[2] FERC, *Assessment of Demand Response and Advanced Metering staff report* (2011).
[3] FERC, *Assessment of Demand Response and Advanced Metering staff report* (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.
[5] The Edison Foundation Institute for Electric Efficiency, *Utility-Scale Smart Meter Deployments, Plans & Proposals* (2012).
[6] EIA, Form EIA-861 and Form EIA-861S: retail_sales_2012 and advanced_meters_2012 data files (October 29, 2013).
[7] The Edison Foundation Institute for Electric Innovation, *Utility-Scale Smart Meter Deployments: A Foundation for Expanded Grid Benefits* (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, 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* (2014).
[10] EIA, Form EIA-861: Advanced_Meters_2014 data file (re-released January 13, 2016).
[11] EIA, Form EIA-861: Advanced_Meters_2015 data file (re-released November 1, 2016).
[12] The Edison Foundation Institute for Electric Innovation, *Electric Company Smart Meter Deployments: Foundation for A Smart Grid* (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 2015 EIA data,[3] 64.7 million advanced meters were operational out of a total of 150.8 million meters nationwide, indicating a 42.9 percent penetration rate. This penetration of advanced meters represents significant growth over the previous year, when EIA reported that 58.5 million advanced meters were operational out of a total of 144.3 million meters, representing a 40.6 percent penetration rate.[4] From 2007 to 2015, the number of advanced meters in operation has grown almost ten-fold.

Table 2-2 below provides estimated advanced metering penetration rates by NERC region, Alaska (AK) and Hawaii (HI),[5] and retail customer class. Advanced meters represent more than half of the meters in three regions: 81.7 percent of meters in Texas Reliability Entity (Texas RE), 59 percent in Western Electricity Coordinating Council (WECC), and 56.4 percent in Florida Reliability Coordinating Council (FRCC). The largest growth in advanced meter penetration from 2014 to 2015 took place in Southwest Power Pool Regional Entity (SPP RE) and ReliabilityFirst (RF), which saw increases of approximately nine and six percentage points, respectively. In contrast, the 2015 figures for WECC and FRCC are slightly lower than in 2014.

Table 2-2 indicates that, nationwide, advanced meters are fairly evenly distributed across customer sectors, accounting for 43.3 percent of residential meters, 40.4 percent of commercial meters, and 37.5 percent of industrial meters. However, within regions, the data indicates significant variation in advanced meter penetration. For example, in Texas RE, ReliabilityFirst, SPP RE, WECC, and AK, the residential and commercial sectors have higher rates of advanced meter penetration than the industrial sector. In contrast, in FRCC, HI, and MRO, the highest penetration of advanced meters is in the industrial sector.

[3] EIA, Form EIA-861 Advanced_Meters_2015 data file (re-released November 1, 2016).

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

[5] 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 (RF), SERC Reliability Corporation (SERC), Southwest Power Pool Regional Entity (SPP RE), Texas Reliability Entity (Texas RE), and Western Electricity Coordinating Council (WECC). Note that the names of some NERC regions have been updated since the previous annual report, specifically ReliabilityFirst (RF), SPP Regional Entity (SPP RE) and Texas Reliability Entity (Texas RE). The states of Alaska (AK) and Hawaii (HI) are not subject to NERC oversight. *See* NERC, *NERC Regions Map*, http://www.nerc.com/AboutNERC/keyplayers/PublishingImages/2017_NERC_Regions_May2017.jpg.

**Table 2-2: Estimated Advanced Meter Penetration by Region and Customer Class (2015)**

| Region | Customer Class | | | |
|---|---|---|---|---|
| | Residential | Commercial | Industrial | All Classes |
| AK | 13.4% | 4.7% | 0.1% | 12.0% |
| FRCC | 56.2% | 57.6% | 69.2% | 56.4% |
| HI | 6.1% | 7.2% | 16.2% | 6.2% |
| MRO | 19.9% | 15.7% | 27.4% | 19.5% |
| NPCC | 9.7% | 8.8% | 12.0% | 9.6% |
| RF | 38.1% | 28.9% | 23.0% | 37.1% |
| SERC | 38.9% | 37.5% | 33.2% | 38.7% |
| SPP RE | 49.9% | 44.0% | 36.4% | 48.7% |
| Texas RE | 81.5% | 84.2% | 62.0% | 81.7% |
| WECC | 59.3% | 57.5% | 47.7% | 59.0% |
| Unspecified | 22.8% | 20.0% | 18.8% | 22.4% |
| **All Regions** | **43.3%** | **40.4%** | **37.5%** | **42.9%** |

*Sources*: EIA, 2015 Form EIA-861 Advanced_Meters_2015 data file.

*Note*: The transportation sector data collected by EIA contain a relatively small number of meters, and are not reported here. In addition, 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, as well as other respondents that did not specify a single NERC region. Commission staff has not independently verified the accuracy of EIA data.

## Developments and issues in advanced metering

### *State legislative and regulatory activity related to advanced metering*

Over the past year, electric utilities in a number of states undertook, or are continuing, large-scale deployment of advanced meters and broad grid modernization efforts that can leverage existing or proposed deployments of advanced meters. Below we provide updates on these activities.

- **Arkansas.** On September 19, 2016, Entergy Arkansas filed an application with the Arkansas Public Service Commission (Arkansas PSC) for deployment of advanced meters and AMI throughout its service territory covering over 701,800 customers.[6] Deployment of advanced meters is proposed to begin in 2019 and span three years.[7] On August 11, 2017, the Arkansas PSC staff, Entergy Arkansas, and the Attorney General's Consumer Utility Rate Advocacy Division reached a settlement agreement to support

[6] *In The Matter of Entergy Arkansas, Inc.'s Application for an Order Finding the Deployment of Advanced Metering Infrastructure to be in the Public Interest and Exemption from Certain Applicable Rules*, Docket No. 16-060-U Doc. 18 (Arkansas PSC Sep. 19, 2016), http://www.apscservices.info/pdf/16/16-060-u_18_1.pdf.

[7] *Id.* at 5.

Entergy Arkansas's AMI-deployment application.[8] On October 30, 2017, the Arkansas PSC approved the settlement agreement.[9]

- **California.** The California Public Utilities Commission (CPUC) continued to conduct proceedings into various aspects of grid modernization; most prominently, the Distributed Resources Plans and Integrated Distributed Energy Resources proceedings.[10] In the Distributed Resources Plans proceeding, the CPUC is examining the value of distributed energy resources (DERs) to the distribution system by asking utilities to propose a range of demonstration projects examining various location and technology scenarios. In a February 2017 decision, as part of the Distributed Resources Plan proceeding, the CPUC granted approval to some demonstration projects, rejected others, and approved elements of some other projects.[11] In November 2016, the CPUC issued its Distributed Energy Resource Action Plan. The Action Plan sets out the long-term vision for DERs in the state and policies to support their growth; identifies nearly three dozen action elements; and establishes a framework for coordination across the numerous current CPUC proceedings that impact or touch on DERs.[12]

  In June 2017, the California ISO (CAISO), California's three investor-owned utilities, and the More Than Smart initiative released a paper examining ways to improve coordination between transmission and distribution systems in preparation for higher penetrations of demand response and other DERs.[13] The report provides a variety of recommendations for addressing issues likely to arise in the near-term and mid-term, and the group continued to meet throughout 2017 to further advance a transmission and distribution coordination framework.

- **Colorado.** On July 25, 2017, Colorado Public Utilities Commission (Colorado PUC) granted a settlement agreement between Colorado PUC staff, Public Service Company of Colorado and other parties to implement AMI and voltage sensing meters as part of the Advanced Grid Intelligence and Security Initiative.[14] Initial deployment of 13,000

[8] *Joint Motion to Approve Settlement Agreement, Excuse Witnesses, and Waive Hearing*, Docket No. 16-060-U Doc. 78 (Arkansas PSC Aug. 11, 2017), http://www.apscservices.info/pdf/16/16-060-U_78_1.pdf.

[9] *In The Matter of Entergy Arkansas, Inc.'s Application for an Order Finding the Deployment of Advanced Metering Infrastructure to be in the Public Interest and Exemption from Certain Applicable Rules*, Docket No. 16-060-U, Order No. 8 (Arkansas PSC Aug. 28, 2017), http://www.apscservices.info/pdf/16/16-060-U_93_1.pdf.

[10] *Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans*, Docket No. R.14-08-013 (California PUC Aug. 20, 2014); and *Order Instituting Rulemaking to Create a Consistent Regulatory Framework for the Guidance, Planning, and Evaluation of Integrated Demand-Side Resource Programs*, Docket No. R.14-10-003 (California PUC Oct. 8, 2014), respectively.

[11] *Decision on Track 2 Demonstration Projects*, Docket No. A.15-07-005 (California PUC Jun. 19, 2017), http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M190/K737/190737689.PDF.

[12] CPUC, *California's Distributed Energy Resources Action Plan: Aligning Vision and Action* (2017), http://www.cpuc.ca.gov/uploadedfiles/cpuc_public_website/content/about_us/organization/commissioners/michael_j._picker/der%20action%20plan%20(5-3-17)%20clean.pdf.

[13] California ISO, et al., *Coordination of Transmission and Distribution Operations in a High Distributed Energy Resource Electric Grid* (2017), http://morethansmart.org/wp-content/uploads/2017/06/MTS_CoordinationTransmissionReport.pdf.

[14] *Decision Granting Joint Motion to Approve Unopposed Comprehensive Settlement Agreement; Approving Settlement Agreement with Clarifications; Granting Application as Modified by the Settlement Agreement; and*

voltage sensing meters will start in 2017.[15] Implementation of advanced metering infrastructure and advanced meters throughout Xcel's service territory in Colorado will take place between 2020 and 2024.[16]

- **District of Columbia.** As part of an ongoing proceeding on grid modernization, in January 2017, the staff of the Public Service Commission of the District of Columbia (DC PSC) released a report, Modernizing the Distribution Energy Delivery System for Increased Sustainability (MEDSIS). The MEDSIS report: (1) recommended that the DC PSC undertake several efforts to revise or adopt new definitions to better account for and regulate distributed energy resources (including demand response) and grid modernization efforts; (b) proposed pilot project grant parameters related to energy delivery system modernization; and (c) requested initial comments on the report by April 10, and reply comments by May 10, 2017.[17] On November 3, 2017, building on the MEDSIS report, the DC PSC proposed several rulemakings to provide regulatory clarity in order to facilitate additional public input into modernizing the District's electricity grid.[18]

- **Hawaii.** On June 30, 2017, Hawaiian Electric Company (HECO Companies) filed a revised draft Grid Modernization Strategy[19] in response to the Hawaii Public Utilities Commission's (Hawaii PUC) concern over the cost of an initial plan filed by HECO Companies in March 2016.[20] The new proposal includes "surgical" deployment of advanced meters to customers with distributed resources and customers that wish to participate in demand response and variable rate programs.[21] On August 29, 2017, the

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*Granting a Certificate of Public Convenience and Necessity*, Proceeding No. 16A-0588E (Colorado PUC Jul. 25, 2017), https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=869033.

[15] *In The Matter Of The Application Of Public Service Company Of Colorado For An Order Granting A Certificate Of Public Convenience And Necessity For Distribution Grid Enhancements, Including Advanced Metering And Integrated Volt-VAR Optimization Infrastructure*, Proceeding No. 16A-0588E (Colorado PUC Jul. 25, 2017) at 5, https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=869033.

[16] *Id*.

[17] *MEDSIS Staff Report*, Formal Case No. 1130 (DC PSC Jan. 25, 2017), http://edocket.dcpsc.org/edocket/docketsheets_pdf_FS.asp?caseno=FC1130&docketno=88&flag=D&show_result=Y.

[18] *In the Matter of the Investigation into Modernizing the Energy Delivery System for Increased Sustainability*, Formal Case No. 1130 (DC PSC Nov. 3, 2017), https://edocket.dcpsc.org/apis/pdf_files/2ef64b14-b635-42ae-b2d2-883f75082567.pdf.

[19] Hawaiian Electric Company, *Modernizing Hawai'i's Grid for Our Customers* (2017), https://www.hawaiianelectric.com/Documents/about_us/investing_in_the_future/grid_modernization_strategy_draft.pdf.

[20] *In the Matter of the Application of Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited For Approval to Commit Funds in Excess of $2,500,000 for the Smart Grid Foundation Project, to Defer Certain Computer Software Development Costs, to Recover Capital and Deferred Costs through the Renewable Energy Infrastructure Surcharge, and Related Requests*, Docket No. 2016-0087 (Hawaii PUC Jan. 4, 2017).

[21] Hawaiian Electric Company, *Modernizing Hawai'i's Grid for Our Customers* (2017) at 86, https://www.hawaiianelectric.com/Documents/about_us/investing_in_the_future/grid_modernization_strategy_draft.pdf.

Hawaii PUC opened a new proceeding to serve as a repository for HECO Companies' Final Grid Modernization Strategy and related filings.[22]

- **Illinois.** In 2016, Commonwealth Edison (ComEd)—the state's largest utility—installed over 1.1 million advanced meters in its service territory, as part of its Advanced Metering Infrastructure Program.[23] The advanced meters helped ComEd avoid nearly 37,000 outage restoration-related truck dispatches in 2016 due to the ability to identify outages remotely, resulting in significant operational savings for customers.[24] ComEd plans to supply its entire service territory with advanced meters by the end of 2019.[25] Ameren Illinois, the state's second largest utility, also plans to supply its entire service territory with advanced meters by 2019.[26]

  In March 2017, the Illinois Commerce Commission (ICC) initiated a collaborative grid modernization process called NextGrid,[27] which will explore several grid modernization topics, including investment in smart grid technology such as advanced meters and smart inverters over an 18 month period.[28] The NextGrid process comes after state enactment of the December 2016 Future Energy Jobs Act, which includes comprehensive changes to various aspects of Illinois energy policy.[29]

  In July 2017, the ICC finalized the Open Data Access Framework, which will govern access to utility customer energy usage data.[30] ComEd and Ameren are first addressing the framework requirements by creating "data roadmaps" for customer data access.

- **Indiana.** In February 2017, Vectren South filed a petition with the Indiana Utility Regulatory Commission (Indiana URC) for approval of a seven year grid modernization plan.[31] Vectren proposed to install 153,000 advanced meters between 2017 and summer

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22 *Instituting a Proceeding Related to the Hawaiian Electric Companies' Grid Modernization Strategy*, Docket No. 2017-0226 (Hawaii PUC Aug. 29, 2017), at 1, http://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A17H30B05116F00989.

23 Commonwealth Edison, *Smart Grid Advanced Metering Annual Implementation Progress Report* (2017) at 4, https://www.icc.illinois.gov/downloads/public/2017%20AIPR%20FINAL.pdf.

24 *Id.* at 34.

25 *Id.* at 64.

26 *Verified Petition for Approval of Smart Grid Advanced Metering Infrastructure Deployment Plan*, Docket No. 12-0244 (ICC Sep. 22, 2016), https://www.icc.illinois.gov/downloads/public/edocket/434480.pdf.

27 *Regarding Illinois' Consideration of the Utility of the Future: "NextGrid" Grid Modernization Study*, Illinois Commerce Commission on its own Motion (ICC Mar. 22, 2017), https://www.icc.illinois.gov/downloads/public/ICC%20Utility%20of%20the%20Future%20Resolution.pdf.

28 Press Release, Illinois Commerce Commission, *ICC Releases Initial Comments in NextGrid* (2017), https://www.icc.illinois.gov/downloads/public/Press%20Release%20-%20%20Initial%20NextGrid%20Comments%20(FINAL).pdf.

29 State of Illinois, Future Energy Jobs Bill (SB 2814), Public Act 99-0906, enacted December 7, 2016, http://www.ilga.gov/legislation/publicacts/99/PDF/099-0906.pdf.

30 *Proceeding to Adopt the Illinois Open Data Access Framework*, Docket No. 14-0507 (ICC Jul. 26, 2017), https://www.icc.illinois.gov/downloads/public/edocket/450960.pdf.

31 *Verified Petition of Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc.*, Cause No. 44910 (Indiana URC Feb. 23, 2017),

2019, with an initial deployment of 2,000 meters to determine the need for any improvements in meter installation procedures and customer communications prior to the full rollout.[32] Subsequently, Vectren South agreed in a settlement to remove the AMI portion from the seven-year plan, and proposed to defer cost recovery of its AMI program until its next rate proceeding.[33]

- **Iowa.** In January 2017, Interstate Power and Light (IPL) filed with the Iowa Utilities Board a request for waiver of full analog meter testing since IPL proposes to deploy advanced meters.[34] IPL proposes to install approximately 470,000 residential and small commercial advanced meters between 2017 and 2019.[35] IPL plans to recover the total costs of AMI and advanced meters in future rate cases once in service.[36] On March 22, 2017, the Iowa Utilities Board (IUB) granted the waiver for three years from the approval date or until IPL completes meter replacement, whichever comes first.[37]

- **Louisiana.** In November 2016, Entergy Louisiana filed an application with the Louisiana Public Service Commission (Louisiana PSC) to deploy advanced meters to 1.1 million electric customers.[38] Entergy Louisiana proposes a first phase of deployment of advanced meters in 2019 with full implementation by the end of 2021.[39] On June 30, 2017, the Louisiana PSC approved Entergy Louisiana's proposal through a settlement agreement.[40]

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https://iurc.portal.in.gov/_entity/sharepointdocumentlocation/32b950ff-eff9-e611-80fd-1458d04e2f50/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=44910_Vectren%20South_Electric%20TDSIC%20Petition_022317.pdf.

[32] *Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. (Vectren South), Exhibit No. 4 (Direct Testimony of Daniel C. Bugher)*, Cause No. 44910 (Indiana URC Feb. 23, 2017) at 16, https://iurc.portal.in.gov/_entity/sharepointdocumentlocation/267e1e47-01fa-e611-8104-1458d04e8ff8/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=44910_Vectren%20South_No%204_Direct%20Testimony%20and%20Attachments_Bugher_022317.pdf.

[33] *Verified Petition of Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc., for Approval of Petitioner's 7-Year Electric TDSIC Plan for Eligible Transmission, Distribution and Storage System Improvements, Pursuant to Ind. Code §8-1-39-10(A), for Authority to Defer Costs for Future Recovery, and Approving Inclusion of Vectren South's TDSIC Plan Projects in its Rate Base in its Next General Rate Proceeding Pursuant to Ind. Code §8-1-2-23*, Cause No. 44910 (Indiana URC Jul. 7, 2017), https://iurc.portal.in.gov/_entity/sharepointdocumentlocation/247f8d20-3463-e711-810d-1458d04e9f68/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=44910_Vectren%20South_Submission%20of%20Proposed%20Order_070714.pdf.

[34] *Request for Temporary Waiver of 199 IAC 1.3*, Docket No. WRU-2017-0004-0150 (IUB Jan. 23, 2017), https://efs.iowa.gov/cs/groups/external/documents/docket/mdax/njey/~edisp/1612040.pdf.

[35] *Id.* at 4.

[36] *Id.* at fn. 9.

[37] *In Re: Interstate Power and Light Company*, Docket No. WRU-2017-0004-0150 (IUB Mar. 22, 2017) https://efs.iowa.gov/cs/groups/external/documents/docket/mdax/nje3/~edisp/1617953.pdf.

[38] *Application of Entergy Louisiana, LLC for Approval to Implement a Permanent Advanced Metering System and Request for Cost Recovery and Related Relief*, Docket No. U-34320 (Louisiana PSC Nov. 22, 2016), http://lpscstar.louisiana.gov/star/ViewFile.aspx?Id=51fab1da-0282-4147-a902-7a64b82a128b.

[39] *Id.* at 9.

[40] *In Re Application of Entergy Louisiana, LLC for Approval to Implement a Permanent Advanced Metering System and Request for Cost Recovery and Related Relief*, Docket No. U-34320 (Louisiana PSC Jun. 30, 2017), http://lpscstar.louisiana.gov/star/ViewFile.aspx?Id=f12761ba-f152-4791-b184-2f3f577b3034.

- **Maryland.** On August 15, 2017, Southern Maryland Electric Cooperative (SMECO), in accordance with a 2013 Maryland Public Service Commission (Maryland PSC) Order,[41] released its latest metrics report on advanced meter deployments.[42] In the 2017 report, SMECO reported a total installation of 96,546 advanced meters covering 60 percent of customers in its service territory. Throughout 2017, SMECO plans to install approximately 14,000 advanced meters per month[43] with full deployment expected by the first quarter of 2018.[44]

  As part of a Maryland PSC grid modernization proceeding,[45] the Maryland PSC is addressing rate design, electric vehicles, competitive markets and customer choice (including enabling utilities that have deployed AMI to begin instituting a data sharing system), the interconnection process, energy storage, and distribution system planning. The Maryland PSC held an initial public hearing in December 2016 and initiated a series of four working groups to study rate design, competitive markets and consumer choice, interconnection, and energy storage.

- **Massachusetts.** As reported in the 2016 version of this staff report,[46] Eversource and National Grid submitted grid modernization plans in 2015 to achieve "advanced metering functionality"[47] as required by the Massachusetts Department of Public Utilities (Massachusetts DPU). Eversource plans to initiate a program allowing customers to replace their existing meters with advanced meters on an opt-in basis.[48] The opt-in

[41] *In the Matter of the Request of Southern Maryland Electric Cooperative, Inc., for Authorization to Proceed with Implementation of an Advanced Metering Infrastructure System*, Case No. 9294, (Maryland PSC Jun. 21, 2013), http://webapp.psc.state.md.us/newIntranet/Casenum/NewIndex3_VOpenFile.cfm?ServerFilePath=C:\Casenum\9200-9299\9294\\43.pdf.

[42] *AMI Metrics Reporting*, *Q2 2017*, Case No. 9294 (Maryland PSC Aug. 15, 2017), http://webapp.psc.state.md.us/newIntranet/Casenum/NewIndex3_VOpenFile.cfm?filepath=C:\Casenum\9200-9299\9294\Item_89\\CaseNo9294MetricsV8-2017Q2.pdf.

[43] SMECO, *SMECO will be Installing Smart Meters in 2017* (Dec. 2016), https://smeco.coop/news/cooperative-review/201612/articleonejump.

[44] SMECO, *AMI Installation Update* (Aug. 2016), https://smeco.coop/news/cooperative-review/201608/articlefourjump.

[45] *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 Sep. 26, 2016), http://www.psc.state.md.us/wp-content/uploads/PC44-Notice-of-Public-Conference.pdf.

[46] FERC, *Assessment of Demand Response and Advanced Metering* at 9 (2016), https://www.ferc.gov/legal/staff-reports/2016/DR-AM-Report2016.pdf.

[47] 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*, Docket No. 12-76-B (Massachusetts DPU Jun. 12, 2014) at 11, http://170.63.40.34/DPU/FileRoomAPI/api/Attachments/Get/?path=12-76%2fOrder_1276B.pdf.

[48] *NSTAR Electric Company and Western Massachusetts Electric Company, each d/b/a Eversource Energy, Incremental Grid Modernization Plan*, Docket Nos. 15-122/15-123 (Massachusetts DPU Feb. 3, 2017), http://170.63.40.34/DPU/FileRoomAPI/api/Attachments/Get/?path=15-122%2fEversource_IGMP_2317.pdf. *See also Petition of NSTAR Electric Company and Western Massachusetts Electric Company, each d/b/a Eversource*

program, Eversource estimates, would limit the amount of advanced meter replacements deployed from 2018 through 2033.[49] Eversource argues that a full deployment of advanced meters to all its customers would not be cost-effective.[50]

Also in August 2017, the Massachusetts DPU held an evidentiary hearing related to National Grid's proposed grid modernization plan from August 2015. The plan includes three potential paths that would result in full deployment of advanced meters and replace 1.3 million meters.[51]

In addition to the ongoing grid modernization proceeding, Eversource proposed a Grid Modernization Base Commitment, which includes several investments to modernize its distribution grid: (1) creation of a distribution system network operator ($44 million), (2) distribution system automation ($84 million), (3) foundational technology for a distribution management system ($111 million), (4) energy storage research and demonstration projects ($100 million), (5) customer tools for Distributed Energy Resource (DER) integration ($15 million), and (6) electric vehicle infrastructure and vehicle conversions ($45 million).[52] Eversource's goal for its distribution system is two-way flow capability, intelligent automation, and active management by network operators that will allow for uses such as demand-side management and generation control.[53] To achieve this goal, a distribution system operator will allow Eversource to turn real-time data into actionable information to complement investment in devices and software systems that make their distribution grid more automated.[54]

- **Mississippi.** In November 2016, Entergy Mississippi filed an application with the Mississippi Public Service Commission (Mississippi PSC) for approval to implement advanced meters throughout its service territory covering 445,000 customers with an opt-out provision.[55] Entergy Mississippi estimates a three-year deployment schedule

*Energy for Approval of Grid Modernization Plan*, Docket No. 15-122 (Massachusetts DPU Aug. 19, 2015), http://170.63.40.34/DPU/FileRoomAPI/api/Attachments/Get/?path=15-122%2fInitial_Filing_Petition.pdf.

49 *Information Request Response DPU-4-2*, Docket Nos. 15-122/15-123 (Massachusetts DPU Mar. 31, 2017), http://170.63.40.34/DPU/FileRoomAPI/api/Attachments/Get/?path=15-122%2fDPU4002.pdf.

50 *Reply Brief of Eversource Energy*, Docket Nos. 15-122/15-123 (Massachusetts DPU Aug. 18, 2017) at 6, 10-11, http://170.63.40.34/DPU/FileRoomAPI/api/Attachments/Get/?path=15-122%2fEversource_Reply_Brief_81817.pdf.

51 *Petition of National Grid for Approval of its Grid Modernization Plan*, Docket No. 15-120 (Massachusetts DPU Aug. 19, 2015) at 14-17, http://170.63.40.34/DPU/FileRoomAPI/api/Attachments/Get/?path=15-120%2fGrid_Mod_PlanFinalRedacted_Boo.pdf.

52 *Petition of NSTAR Electric Company and Western Massachusetts Electric Company, each d/b/a Eversource Energy, Volume 3, Grid Modernization Base Commitment Investment Plan*, Docket No. 17-05 (Massachusetts DPU Jan. 17, 2017), http://170.63.40.34/DPU/FileRoomAPI/api/Attachments/Get/?path=17-05%2fESGMBC2_Investment_Plan.pdf.

53 *Eversource Grid Modernization Base Commitment*, Docket No. 17-05 (Massachusetts DPU Jan. 17, 2017) at 17, http://170.63.40.34/DPU/FileRoomAPI/api/Attachments/Get/?path=17-05%2fESGMBC2_Investment_Plan.pdf.

54 *Id.* at 14-16.

55 *Application for Approval of Advanced Metering Infrastructure and Related Modernization Improvements*, Docket No. 2016-UA-261 (Mississippi PSC Nov. 2016), http://www.psc.state.ms.us/InSiteConnect/InSiteView.aspx?model=INSITE_CONNECT&queue=CTS_ARCHIVEQ&docid=380265.

beginning in 2019.[56] On May 1, 2017, the Mississippi PSC approved Entergy's proposal.[57]

- **New Hampshire.** In March 2017, New Hampshire's Grid Modernization Working Group submitted its final report to the New Hampshire Public Utilities Commission.[58] The effort covered distribution system planning, advanced metering functionality, rate design, customer data and education, and utility cost recovery and financial incentives. The working group report recommends that each utility develop grid modernization plans with a stakeholder engagement process.

- **New Mexico.** In February 2016, Public Service Company of New Mexico (PNM) filed a proposal with the New Mexico Public Regulation Commission (New Mexico PRC) to deploy advanced meters to its 531,000 customers.[59] Public hearings were held in February and March 2017 and a decision by the New Mexico PRC is expected by the end of 2017.[60] If the proposal is approved, PNM expects deployment to begin in early 2018 and end in 2019.[61]

- **New York.** On April 28, 2017, National Grid filed a rate plan with the New York Public Service Commission (New York PSC) seeking, among other things, approval to deploy advanced meters.[62] Over the span of four years, beginning in 2021, National Grid's plan would result in a deployment of more than 1.6 million advanced meters across its service territory.[63]

  In March 2017, the New York PSC published an order on Distributed System Implementation Plans.[64] In the order, the New York PSC provided guidance to utilities

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[56] *Id.* at 11.
[57] *In Re Application for Approval of Advanced Metering Infrastructure and Related Modernization Improvements*, Docket No. 2016-UA-261 (Mississippi PSC May 1, 2017), http://www.psc.state.ms.us/InSiteConnect/InSiteView.aspx?model=INSITE_CONNECT&queue=CTS_ARCHIVEQ&docid=386172.
[58] *Grid Modernization in New Hampshire*, Grid Modernization Working Group, Final Report (Mar. 20, 2017), http://www.raabassociates.org/Articles/NH%20Grid%20Mod%20Final%20Report%203-20-2017.pdf.
[59] *In the Matter of the Application of Public Service Company of New Mexico for Prior Approval of the Advanced Metering Infrastructure Project, Determination of Ratemaking Principles and Treatment, and Issuance of Related Accounting Orders*, Case No. 15-00312-UT (New Mexico PSC Feb. 2016), https://www.pnm.com/documents/396023/428013/2016+Customer+Notice+AMI.pdf/55282147-12f9-4635-875a-2b49bf967a2a.
[60] Public Service Company of New Mexico, *What is Smart Meter Infrastructure?*, https://www.pnm.com/ami.
[61] *Id*.
[62] *Niagara Mohawk Power Corporation d/b/a National Grid Proceeding On Motion Of The Commission As To The Rates, Charges, Rules And Regulations Of Niagara Mohawk Power Corporation For Electric And Gas Service, Book 9 (Testimony and Exhibits of Advanced Metering Infrastructure Panel)*, Case No. 17-E-0238 (New York PSC Apr. 28, 2017), http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={224F9FD6-8CFA-47E4-98A9-88F5B0A149A4}.
[63] *Id.* at 7.
[64] *In the Matter of Distributed System Implementation Plans, Order on Distributed System Implementation Plan Filings*, Case No. 16-M-0411 (New York PSC Mar. 9, 2017),

on hosting capacity, applying for interconnection online, non-wire alternatives, data privacy, and energy storage, as a part of the state's energy strategy, "Reforming the Energy Vision."

- **North Carolina.** As part of the North Carolina Utilities Commission's (NCUC) 2016 Biennial Integrated Resource Plans and Renewable Energy and Energy Efficiency Portfolio Standard Compliance proceeding, the investor-owned utilities in North Carolina were required to submit 5-year Smart Grid Technology Plans. The NCUC approved the utilities' plans in March 2017, but also requested that NCUC staff, utilities and all interested parties continue discussing potential rule changes for customer data access.[65] The plans submitted by the utilities vary and include a wide mix of smart grid technologies, including advanced meter deployment. The utilities subsequently filed 2017 updates to their integrated resource plans in the same docket.[66]

- **Ohio.** On February 1, 2017, the Public Utilities Commission of Ohio (PUCO) approved AEP Ohio's application to implement Phase 2 of its gridSMART Project.[67] AEP Ohio will install AMI for approximately 894,000 customers over four years beginning in 2017.[68] As part of a settlement agreement, AEP Ohio is required to develop time-of-use rate options and programs. Customers are expected to incur $200 million in operational savings from AMI deployment.[69]

  PUCO announced the launch of a PowerForward grid modernization investigation in March 2017.[70] PUCO intends to use the study to establish a path for future grid modernization projects and regulations that can improve the consumer experience. After conducting hearings on utility reform and new technologies, PUCO expects to begin formal ratemaking and regulatory proceedings to address grid modernization in early 2018.

- **Oregon.** In July 2017, the Oregon legislature enacted a bill requiring the Oregon Public Utility Commission (Oregon PUC) to investigate grid modernization.[71] The legislation requires the Oregon PUC to establish a public process to investigate developing industry

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http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={35E255DD-92FF-420B-8363-895892992103}.

[65] *Order Accepting Smart Grid Technology Plans*, Docket No. E-100, Sub 147 (North Carolina UC Mar. 29, 2017), http://starw1.ncuc.net/ncuc/ViewFile.aspx?Id=cd65f9a8-2bd9-457d-96d2-4df1a454a219.

[66] Duke Energy Carolinas, *North Carolina 2017 Integrated Resource Plan (Updated Report)* (Sep. 1, 2017), http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=05fb2b10-a879-4a9e-a881-f9cbb60a69a5; and Duke Energy Progress, *North Carolina Integrated Resource Plan (Update Report)* (Sep. 1, 2017), http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=040feb17-3f8b-4b6b-b620-b1cac673e7e1.

[67] *In the Matter of the Application of Ohio Power Company to Initiate Phase 2 of its gridSMART Project and to Establish the gridSMART Phase 2 Rider*, Case No. 13-1939-EL-RDR (Ohio PUC Feb. 1, 2017), http://dis.puc.state.oh.us/TiffToPDf/A1001001A17B01B42659J00896.pdf.

[68] *Id.* at 8.

[69] *Id.* at 20.

[70] Ohio PUC, *PowerForward*, https://www.puco.ohio.gov/industry-information/industry-topics/powerforward/.

[71] State of Oregon, SB 978, 2017 Regular Session, enacted on August 16, 2017, https://olis.leg.state.or.us/liz/2017R1/Downloads/MeasureDocument/SB978/Enrolled.

trends, technologies and how policy drivers in the electricity sector affect the existing regulatory system and incentives currently employed by the Oregon PUC. Its investigation could include advanced meters. If warranted, the Oregon PUC may consider changes to its existing rules.

- **Rhode Island.** In March 2017, the Governor of Rhode Island directed the Rhode Island Public Utilities Commission (Rhode Island PUC), Office of Energy Resources, and Division of Public Utilities and Carriers to design a new regulatory framework for Rhode Island's electric system.[72] Distribution system planning is being considered as part of this effort. In response, on June 15, 2017, the Rhode Island PUC held a technical meeting on "Grid Connectivity and Functionality," as part of a grid modernization initiative called Power Sector Transformation.[73] On August 15, 2017, the Rhode Island PUC also submitted initial proposals to stakeholders regarding Distribution System Planning[74] improvements, inviting stakeholders to comment on the proposals to further inform the PUC on next steps.[75] In November 2017, the three agencies delivered their phase one report to the Governor, recommending, among other things, that National Grid develop a plan for rolling out an advanced meter platform that provides certain capabilities, including time-varying rates.[76]

- **Texas.** On July 18, 2017, Entergy Texas filed an application with the Public Utility Commission of Texas (PUCT) for approval of its advanced metering system plan.[77] Entergy Texas proposes to deploy 477,000 advanced meters over a three year deployment period beginning in 2019.[78] Entergy Texas reached a settlement in principle with Commission staff and the Office of Public Utility Counsel and on September 11, 2017, Entergy Texas filed a motion with the PUCT to abate the remaining procedural schedule.[79]

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[72] *Letter to Rhode Island PUC*, Rhode Island Office of Energy Resources, and Rhode Island Division of Public Utilities and Carriers, (Office of the Governor of Rhode Island, Mar. 2, 2017), http://www.ripuc.ri.gov/utilityinfo/electric/GridMod_ltr.pdf.
[73] Rhode Island Public Utilities Commission, *Power Sector Transformation Initiative* (2017), http://www.ripuc.org/utilityinfo/electric/PST_home.html.
[74] *Initial Proposals for Distribution System Planning Improvements and Request for Stakeholder Comment* (Rhode Island PUC Aug. 15, 2017), http://www.ripuc.org/utilityinfo/electric/DSP_Workstream_proposals_8_15.pdf.
[75] *Id*.
[76] Rhode Island Division of Public Utilities & Carriers, Office of Energy Resources and Public Utilities Commission, *Rhode Island Power Sector Transformation: Phase One Report to Governor Gina M. Raimondo* (Nov. 2017) at 10, 41-42, Appendix II, http://www.ripuc.org/utilityinfo/electric/PST%20Report_Nov_8.pdf.
[77] *Application of Entergy Texas, Inc. for Approval of Advanced Metering System (AMS) Deployment Plan, AMS Surcharge, and Non-Standard Metering Service Fees*, Docket No. 47416 (PUCT Jul. 18, 2017), http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/47416_1_948263.PDF.
[78] *Id.*, Attachment A, Entergy Texas, Inc.'s Advanced Metering System Deployment Plan, at 17.
[79] *Id.*, *Unopposed Motion to Abate the Procedural Schedule* (PUCT Sep. 11, 2017), http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/47416_47_954390.PDF.

### *Collaborative industry-government efforts*

On March 7, 2016, NAESB, working with the Smart Grid Interoperability Panel (SGIP)[80] and other stakeholders, developed and ratified voluntary Open Field Message Bus (OpenFMB) business standards. An OpenFMB architecture enables communication and information exchange between advanced meters and other utility and third-party devices (e.g., relays, inverters, reclosers). By the end of 2017, NAESB expects to complete cyber-security model business standards for the OpenFMB architecture.[81]

In addition, the SGIP[82] launched an OpenFMB collaboration website in November 2016.[83] SGIP published OpenFMB software with installation and configuration instructions, as well as information and utility use cases that support distributed intelligence. SGIP expects the distribution of OpenFMB software code using the open source model to increase the base of utility participation, assist utilities in developing new applications to solve interoperability and legacy systems integration issues, and lead to new innovations.[84]

[80] SGIP has since merged with the Smart Electric Power Alliance. *See SGIP, SEPA and SGIP Announce Intent to Merge*, February 1, 2017, http://www.sgip.org/sepa-sgip-announce-intent-merge/.
[81] *NAESB Board Executive Committee Meeting, Wholesale Electric Quadrant, Green Button & Open FMB Update, Dallas, Texas*, Aug. 15, 2017, https://www.naesb.org/misc/greenbutton_update_072617.docx.
[82] SGIP, and industry consortium focused on accelerating grid modernization, has since merged with the Smart Electric Power Alliance. *See SGIP, SEPA and SGIP Announce Intent to Merge*, Feb. 1, 2017, http://www.sgip.org/sepa-sgip-announce-intent-merge/.
[83] Smart Grid Interoperability Panel, *SGIP Gives Access to the OpenFMB™ Framework for Distributed Intelligence in the Grid*, Nov. 7, 2016, http://www.sgip.org/sgip-gives-access-openfmbtm-framework-distributed-intelligence-grid/.
[84] Aaron Smallwood, *Guest Editorial: OpenFMB™ Brings a Standard and a New Tool Set to the Grid's Edge*, July/August 2016, http://www.electricenergyonline.com/show_article.php?mag=114&article=973#.

# 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.[85]

## Retail demand response programs

Table 3-1 presents data collected by EIA on 2014 and 2015 potential peak demand savings[86] from retail demand response programs within each of the eight NERC regional entities, as well as Alaska and Hawaii.[87] Nationwide, total potential peak demand savings from retail demand response programs increased by 1,684 megawatts (MW), or 5.4 percent, between 2014 and 2015.

**Table 3-1: Potential Peak Demand Savings (MW) from Retail Demand Response Programs by Region (2014 & 2015)**

| Region | Annual Potential Peak Demand Savings (MW) | | Year-on-Year Change | |
|---|---|---|---|---|
| | 2014 | 2015 | MW | % |
| AK | 27 | 27 | 0 | 0.0% |
| FRCC | 3,389 | 3,247 | -143 | -4.2% |
| HI | 41 | 35 | -6 | -13.9% |
| MRO | 4,366 | 4,509 | 143 | 3.3% |
| NPCC | 654 | 787 | 133 | 20.3% |
| RF | 5,006 | 5,372 | 366 | 7.3% |
| SERC | 8,343 | 9,259 | 916 | 11.0% |
| SPP RE | 1,324 | 1,923 | 598 | 45.2% |
| Texas RE | 613 | 696 | 83 | 13.6% |
| WECC | 7,427 | 7,019 | -407 | -5.5% |
| **Total** | **31,191** | **32,875** | **1,684** | **5.4%** |

*Sources*: EIA, EIA-861 Demand_Response_2014, Demand_Response_2015, Utility_Data_2014, and Utility_Data_2015 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 demand savings from 2014 to 2015. For example, Table 3-1 above indicates potential peak demand savings increased in the SERC region by more than 900 MW compared to the previous year; this can be attributed to an increase in reported savings from programs operated by several utilities,

[85] The latest publicly available retail and wholesale data sets are used to determine the annual resource contributions from demand response programs; these include EIA retail data for 2014 and 2015, as well as ISO/RTO wholesale data for 2015 and 2016.

[86] 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." *See* EIA, Form EIA-861 Instructions, Schedule 6, Part B.

[87] This section categorizes potential peak demand savings from retail demand response programs by NERC region because such programs exist in regions both with and without organized wholesale markets.

including Duke Energy Progress, Duke Energy Carolinas, Gulf Power, Alabama Power, and Woodruff Electric Cooperative. Increased demand response potential in the SPP RE region was largely due to greater reported savings from demand response programs of Kansas Gas & Electric, Oklahoma Gas & Electric, and Northfork Electric Cooperative. Demand response potential in ReliabilityFirst returned to the level seen in 2013, after falling in 2014. This was due to greater reported savings by PEPCO, Duke Energy Ohio, Appalachian Power, Indiana Michigan Power, and Duke Energy Kentucky. In contrast, net demand response potential fell sharply in WECC in 2015, due primarily to lower reported savings in Southern California Edison's industrial demand response program, although this was partially offset by higher reported savings in programs run by Sulphur Springs Valley Electric Cooperative and PSCo (Xcel).

As Table 3-2 illustrates, the amount of potential peak demand savings from retail demand response differs by customer class. In 2015, industrial customer demand response represented 17,169 MW, or 52 percent, of total potential peak demand savings. Residential customer demand response accounted for 8,703 MW, or 26 percent, and programs in the commercial sector accounted for 6,989 MW, or 21 percent, of total potential peak demand savings. The relative contribution by customer class varies by region, and has remained fairly stable over time. For example, residential demand response programs account for the largest portion of potential peak demand savings in FRCC (approximately 49 percent) and MRO (approximately 44 percent). In contrast, commercial programs account for the majority of potential peak demand savings in AK, HI, NPCC and Texas RE; and industrial programs account for the majority in ReliabilityFirst, SERC, SPP RE, and WECC.

**Table 3-2: Potential Peak Demand Savings (MW) from Retail Demand Response Programs by Region and Customer Class (2015)**

| Region | Customer Class | | | | |
|---|---|---|---|---|---|
| | Residential | Commercial | Industrial | Transportation | All Classes |
| AK | 5 | 13 | 9 | 0 | 27 |
| FRCC | 1,575 | 1,333 | 338 | 0 | 3,247 |
| HI | 15 | 20 | 0 | 0 | 35 |
| MRO | 1,989 | 734 | 1,786 | 0 | 4,509 |
| NPCC | 120 | 354 | 300 | 14 | 787 |
| RF | 1,491 | 754 | 3,128 | 0 | 5,372 |
| SERC | 1,906 | 841 | 6,512 | 0 | 9,259 |
| SPP RE | 146 | 284 | 1,493 | 0 | 1,923 |
| Texas RE | 164 | 345 | 187 | 0 | 696 |
| WECC | 1,292 | 2,311 | 3,416 | 0 | 7,019 |
| **All Regions** | **8,703** | **6,989** | **17,169** | **14** | **32,875** |

*Sources*: EIA, EIA-861 Demand_Response_2015 and Utility_Data_2015 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.

## Wholesale demand response programs

Table 3-3 below presents demand resource participation in wholesale demand response programs in 2015 and 2016 in the ISO/RTO regions. Across all ISO/RTO regions, demand resource participation fell in 2016 to 28,673 MW, a 10 percent decrease from the previous year, and a level roughly equal to participation in 2013 and 2014. In contrast, peak demand grew by three percent from 2015 to 2016. As a result, the contribution of demand resources to meeting peak demand fell to 5.7 percent in 2016, down from 6.6 percent in 2015. Since 2009, demand resource participation in wholesale markets has increased by approximately six percent, but has been outpaced by an approximately 16 percent increase in peak demand.

This decrease in demand resource participation across the RTO/ISO regions was primarily due to an approximately 24 percent (3,030 MW) drop in demand resource enrollment in PJM Interconnection (PJM), which in turn was due to an almost 2,900 MW decrease in demand response capacity enrolled in PJM's reliability program (Limited, Extended Summer and Annual DR), and a 900 MW decrease in economic program enrollments.[88] These changes were offset by approximately 600 MW of new enrollment of demand response in PJM's Capacity Performance product.[89]

Demand resource participation also fell in CAISO, by eight percent or 163 MW, due to decreased enrollment in price-responsive demand programs administered by the three investor-owned utilities.[90] Participation in utility-sponsored programs has been gradually declining over the last several years, while participation in CAISO's wholesale demand response products has been growing. In 2016, demand resource enrollment in CAISO's two wholesale products totaled 1,480 MW.[91]

In addition, demand resource participation in ISO New England (ISO-NE) and New York Independent System Operator (NYISO) decreased by approximately four percent, compared to a year earlier. In contrast, net demand response participation rose in MISO in 2016, due to an increase in demand resource capacity registered as Emergency Demand Response and Type I Demand Response Resources. This was offset by a decrease in resources registered as other

[88] Some resources participate in both the reliability and economic programs.
[89] Based on comparison of data from *PJM 2015 Demand Response Operations Markets Activity Report* (May 2016), at 3-4; and *PJM 2016 Demand Response Operations Markets Activity Report* (May 2017), at 3-4.
[90] Price-responsive demand programs in California are triggered on a day-ahead or day-of basis in response to market or system conditions that indicate relatively high prices. Specific programs include critical peak pricing, air-conditioning cycling, and load reductions aggregated through curtailment service providers. Price-responsive demand programs administered by the investor-owned utilities include programs that are integrated into CAISO's wholesale products (see *infra* note 88) and are therefore dispatched by CAISO, as well as programs triggered based on utility-specific indicators such as temperature forecasts. *See* CAISO, *2016 Annual Report on Market Issues and Performance* (2017) at 32, http://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf.
[91] In 2016, the proxy demand response (PDR) capacity totaled 160 MW and reliability demand response resource (RDRR) capacity was 1,320MW. *See* CAISO, *2016 Annual Report on Market Issues and Performance* (2017) at 30-31, http://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf.

types of demand response in Midcontinent Independent System Operator (MISO).[92] Demand resource participation also rose slightly in Electric Reliability Council of Texas (ERCOT).

**Table 3-3: Demand Resource Participation in U.S. ISO and RTO Demand Response Programs**

| RTO/ISO | 2015 | | 2016 | |
|---|---|---|---|---|
| | Demand Resources (MW) | Percent of Peak Demand [8] | Demand Resources (MW) | Percent of Peak Demand [8] |
| California ISO (CAISO) | 2,160 [1] | 4.4% | 1,997 [9] | 4.3% |
| Electric Reliability Council of Texas (ERCOT) | 2,100 [2] | 3.0% | 2,253 [10] | 2.9% |
| ISO New England (ISO-NE) | 2,696 [3] | 11.0% | 2,599 [11] | 10.2% |
| Midcontinent Independent System Operator (MISO) | 10,563 [4] | 8.8 % | 10,721 [12] | 8.9% |
| New York Independent System Operator (NYISO) | 1,325 [5] | 4.3% | 1,267 [13] | 3.9% |
| PJM Interconnection (PJM) | 12,866 [6] | 9.0% | 9,836 [14] | 6.5% |
| Southwest Power Pool (SPP) | 0 [7] | 0% | 0 [7] | 0% |
| **Total ISO/RTO** | **31,710** | **6.6%** | **28,673** | **5.7%** |

*Sources:*
[1] CAISO, *2015 Annual Report on Market Issues and Performance*, Table 1.4, at 33 (May 2016).
[2] ERCOT *Quick Facts* (Dec. 2015).
[3] ISO-NE, *ISO-NE Demand Resource Statistics*, presented at Demand Resources Working Group Meeting (Jan. 20, 2016) (data as of Jan. 1, 2016), at 2.
[4] *2015 State of the Market Report for the MISO Electricity Market* (June 2015), Table 5, at 76.
[5] *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, at 7.
[6] *PJM 2015 Demand Response Operations Markets Activity Report* (May 2016), at 3-4. Figure represents "unique MW." Based on PJM data, this figure has been updated since the publication of the 2016 staff report, which reported 12,910 MW.
[7] No load-reduction demand response activity has occurred in the Integrated Marketplace since it was established on March 1, 2014. *See* SPP Compliance Filing, Docket No. ER12-1179-024, at 4 (May 24, 2016).
[8] Sources for peak demand data include: California ISO *2015* and *2016 Annual Reports on Market Issues and Performance*; *ERCOT 2015 & 2016 Demand and Energy Reports*; *ISO-NE Net Energy and Peak Load Report* (May 2016 & May 2017); *2015* and *2016 State of the Market Reports for the MISO Electricity Markets*; *NYISO Power Trends Reports 2016* and *2017*; *2015* and *2016 PJM State of the Markets Reports, Vol. 2*; *SPP Fast Facts* (Feb. 2016) and *2016 Annual Report*.
[9] CAISO, *2016 Annual Report on Market Issues and Performance*, Table 1.3, at 33 (May 2017).
[10] ERCOT *Quick Facts* (May 2016). These are the latest data available.
[11] ISO-NE, *Demand Response Enrollment Statistics*, presented at Demand Resources Working Group Meeting (Jan. 9, 2017) (data as of Jan. 1, 2017), at 2.
[12] *2016 State of the Market Report for the MISO Electricity Market* (June 2016), Table 8, at 72.
[13] *2016 Annual Report on Demand Side Management Programs of the New York Independent System Operator, Inc.*, ER01-3001 (Jan. 12, 2017), Attachment I, Table 1, at 7.
[14] *PJM 2016 Demand Response Operations Markets Activity Report* (May 2017), at 3-4. Figure represents "unique MW."

*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.

[92] Potomac Economics, *2016 State of the Market Report for the MISO Electricity Markets* (2017) at 72, https://www.misoenergy.org/Library/Repository/Report/IMM/2016%20State%20of%20the%20Market%20Report.pdf.

## 2017 summer demand response deployments

High temperatures during the summer of 2017 led grid operators and utilities in several regions to issue notices for economic demand response, critical peak pricing, voluntary conservation, and delayed maintenance. There was no reported dispatch of emergency demand response.

On July 20-21, 2017, economic demand response in PJM responded to high load caused by high temperatures. The estimated hourly economic demand response reached levels of approximately 140 MW and 850 MW on each day, respectively.[93] No emergency resources were called on to respond during this period.[94]

In response to high temperatures in California, CAISO issued state-wide Flex Alerts[95] calling for voluntary electricity conservation on June 20 and 21, August 29 and 31, and September 1, 2017.[96] CAISO also issued several calls for restricted maintenance operations[97] in June, July, and August.[98] Pacific Gas & Electric (PG&E) called fifteen critical peak pricing days, the maximum allowed, over the course of the summer, most recently during record high temperatures in the Bay Area at the beginning of September.[99] Southern California Edison (SCE) also called critical peak pricing days throughout the summer, from mid-June to mid-September.[100] In addition, more than 41,000 residential customers in SCE's territory gave permission for makers of smart thermostats to remotely adjust home temperatures during high expected peak demand at the end of August and in early September. Participation in this Save Power Day program increased from 5,000 customers in 2016.[101]

On August 25, 2017, ERCOT issued an Emergency Notice due to transmission outages caused by Hurricane Harvey. Transmission owners were advised to be prepared to lose load and to

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[93] *PJM Estimated Demand Response Activity July 20-21, 2017*, at 3-4, http://www.pjm.com/-/media/markets-ops/demand-response/pjm-hot-days-report-for-july-20-21-2017.ashx?la=en.

[94] *Id.* at 2.

[95] Flex alerts are voluntary calls for consumers to conserve electricity or shift demand to off-peak hours during heat waves or unexpected system contingencies. *See* CAISO, *Flex Alert*, http://flexalert.org/what-is-flex-alert. *See also* CAISO, *Alerts, Warnings and Emergency Notice Archive*, http://www.caiso.com/informed/Pages/Notifications/AWENoticeLog.aspx.

[96] CAISO, *California ISO issues statewide Flex Alert due to heat wave* (Aug. 29, 2017), http://www.caiso.com/Documents/FlexAlert-CaliforniaISOIssuesStatewideFlexAlertDuetoHeatWave082917.pdf.

[97] This type of notice requires transmission and generator operators to postpone planned routine maintenance outages until further notice.

[98] CAISO, *Alerts, Warnings and Emergency Notice Archive*, http://www.caiso.com/informed/Pages/Notifications/AWENoticeLog.aspx.

[99] PG&E's Peak Day Pricing program is an "optional rate that offers businesses a discount on regular summer electricity rates in exchange for higher prices during nine to 15 Peak Pricing Event Days per year, typically occurring on the hottest days of the summer." *See* PG&E, *Review Peak Day Pricing Day Event History*, https://www.pge.com/en_US/business/rate-plans/rate-plans/peak-day-pricing/event-day-history.page.

[100] Southern California Edison, *Event History*, https://www.sce.openadr.com/dr.website/scepr-event-history.jsf.

[101] Edison International, *SCE Crew Stands Ready for Late-August Heat Wave* (updated Aug. 29, 2017), http://insideedison.com/stories/sce-crews-stand-ready-for-late-august-heat-wave?utm_source=scehomepage; and 89.3 KPCC, *Thousands give up control of home thermostats during a heat wave* (Aug. 28, 2017), https://www.scpr.org/news/2017/08/28/75111/thousands-give-up-control-of-home-thermostats-duri/.

expect high voltage conditions.[102] There were no calls for emergency demand response in ERCOT.

## 2017 solar eclipse

Leading up to the total solar eclipse on August 21, 2017, the EIA estimated that approximately 22 GW of utility-scale solar photovoltaic capacity (about 1,900 plants) would be partially or completely obscured nationwide.[103] A NERC study evaluating potential consequences of the eclipse did not predict any effect on reliable operation of the bulk power system.[104] There were no reports of reliability issues due to the eclipse, and emergency demand response was not dispatched.[105]

In California, which hosts 40 percent of utility-scale solar PV capacity in the U.S., CAISO estimated that it would experience a loss of approximately 4.2 GW of utility-scale and 1.4 GW of rooftop solar capacity during the eclipse. [106] In actuality, utility-scale solar output fell by 3,400 MW, less than expected.[107] In preparation for the eclipse, CAISO had procured approximately 1,000 MW of regulation resources for each hour of the eclipse, much more than the typical hour's 350 MW. As solar generation dropped off after the start of the event, hydropower and natural gas resources ramped up to compensate.[108] CAISO also relied on imports from its Energy Imbalance Market.[109] Although CAISO had previously identified Flex Alerts[110] as one of a number of potential measures to mitigate the effect of the eclipse,[111] neither a Flex Alert nor dispatchable demand response were called to meet system needs during the event. However, as part of its "Do Your Thing for the Sun" campaign leading up to the eclipse, the CPUC received pledges from various organizations and technology providers to help end-users take at least one action during the event to reduce electricity usage, such as replacing light bulbs with LEDs or turning up the thermostat by several degrees.[112]

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[102] ERCOT, *Public Notices*, http://www.ercot.com/services/comm/mkt_notices/notices/2017/08.
[103] EIA, *Solar eclipse on August 21 will affect photovoltaic generators across the country* (Aug. 7, 2017), https://www.eia.gov/todayinenergy/detail.php?id=32372.
[104] NERC, *A Wide-Area Perspective on the August 21, 2017 Total Solar Eclipse* (Apr. 2017), at iv, 20, http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Solar_Eclipse_2017_Final_4-25-17.pdf.
[105] Utility Dive, *US grid untroubled by total eclipse despite plunge in solar output* (Aug. 22, 2017), http://www.utilitydive.com/news/us-grid-untroubled-by-total-eclipse-despite-plunge-in-solar-output/503156/; ISO Newswire, *New England power grid operations during August 21 partial eclipse* (Aug. 22, 2017), http://isonewswire.com/updates/2017/8/22/new-england-power-grid-operations-during-august-21-partial-e.html; Megawatt Daily, *Incident-free eclipse offers lessons for 2024* (Aug. 22, 2017).
[106] CAISO, *FAQ: Solar Eclipse*, http://www.caiso.com/Documents/SolarEclipseFAQ.pdf.
[107] Utility Dive, *US grid untroubled by total eclipse despite plunge in solar output* (Aug. 22, 2017), http://www.utilitydive.com/news/us-grid-untroubled-by-total-eclipse-despite-plunge-in-solar-output/503156/.
[108] EnergyWire, *Grid operators take a stunning event in stride* (Aug. 22, 2017), https://www.eenews.net/stories/1060059019.
[109] SNL, *Eclipse effects on grid less than expected, US system operators say* (Aug. 21, 2017), www.snl.com.
[110] *See supra* note 93.
[111] CAISO, *2017 Solar Eclipse Report* (May 1, 2017), https://www.caiso.com/Documents/Briefing_SolarEclipse-ISOReport-May_2017.pdf.
[112] Greentech Media, *Looking Beyond the Eclipse: How the Historic Event Tested Customer Engagement on the Electric Grid* (Aug. 21, 2017), https://www.greentechmedia.com/articles/read/looking-beyond-eclipse-historic-event-consumer-engagement; CPUC and CEC, *Solar Eclipse*, https://ia.cpuc.ca.gov/caleclipse/.

In PJM, grid-scale solar generation fell by 520 MW during the eclipse, but the region maintained system reliability in part due to a net decrease in demand of 5,000 MW from lower cooling loads, increased cloud cover, and changes in behavior related to the eclipse.[113] Like in California, some of these energy saving behaviors—turning off lights, unplugging appliances—were the result of eclipse-themed marketing and promotional efforts.[114]

ISO-NE, which has approximately 2,000 MW of mostly distributed solar capacity in its footprint, did not experience any reliability issues as a result of the eclipse. Cloud cover before the eclipse, and lower-than-expected temperatures and changes in consumer behavior during the event, lessened the impact of the eclipse on solar generation.[115]

MISO, whose footprint fell within the band of 80-100 percent solar obscuration, has a limited amount of solar capacity—180 MW of utility-scale and 350 MW of distributed solar. As a result, although generation from the utility-scale solar plants dropped almost to zero during the eclipse, MISO was not affected by the eclipse, and took no extraordinary measures to prepare for the event.[116] Likewise, ERCOT and SPP currently have relatively little solar capacity—approximately 700 MW and 325 MW, respectively—and did not experience any reliability issues related to the eclipse.[117]

[113] Utility Dive, *US grid untroubled by total eclipse despite plunge in solar output* (Aug. 22, 2017), http://www.utilitydive.com/news/us-grid-untroubled-by-total-eclipse-despite-plunge-in-solar-output/503156/.
[114] Greentech Media, *For US Grid Markets, an Eclipse Day is Like Any Other Day for Managing Solar Power* (Aug. 23, 2017), https://www.greentechmedia.com/articles/read/for-u-s-grid-markets-an-eclipse-day-is-like-any-other-day.
[115] ISO Newswire, *New England power grid operations during August 21 partial eclipse* (Aug. 22, 2017), http://isonewswire.com/updates/2017/8/22/new-england-power-grid-operations-during-august-21-partial-e.html.
[116] Megawatt Daily, *Incident-free eclipse offers lessons for 2024* (Aug. 22, 2017); *see also* RTO Insider, *MISO Revisits Eclipse Ops, Prepares for 2024*, https://www.rtoinsider.com/miso-caiso-solar-eclipse-48321.
[117] *Id.*; and SPP, *The August 21, 2017 Total Solar Eclipse: SPP Impact* (2017), https://www.spp.org/documents/53556/analysis%20of%20august%20eclipse%20final_v2.0%20(002).pdf.

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

NERC oversees the reliability of the North American bulk power system, provides an independent assessment of bulk power system reliability, and measures system performance with established sets of reliability indicators (i.e., metrics).[118] NERC notes that the bulk power system is integrating more demand response resources, as well as other distributed and renewable energy resources,[119] and states that it considers visibility of distributed resources by system operators crucial to system planning, forecasting, and modeling.[120] NERC is working to improve the quality of the demand response data it collects to provide a better perspective on how demand response is being used to support planning and operations of a reliable bulk power system.[121] In addition to collecting and presenting reliability demand response data and results, NERC continues its efforts to integrate economic demand response within the DADS database.[122]

Utilities and wholesale market operators that administer demand response programs are required to report demand response registration, event, and market participation information into the DADS database. NERC demand response program data is collected for summer (April 1 through September 30) and winter (October 1 through March 31) seasons. Using available DADS data through September 2016, NERC reports that total registered summer capacity increased slightly since 2013 but remained relatively flat from 2015, and total registered winter capacity experienced a 12.7 percent increase from 2015, due largely to changes in program rules and implementation of new programs.[123] NERC also advises, but for the summer of 2013, the realized demand reduction rate continues to be above 90 percent during both summer and winter periods, and that the variability at which demand response is deployed throughout the country is more of "a function of the demand response programs' designs rather than an indication of extensive reliability issues within a region."[124]

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[118] NERC, *State of Reliability 2017* (Jun. 2017) at vi, http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/SOR_2017_MASTER_20170613.pdf.
[119] NERC, Distributed Energy Resources: Connection Modeling and Reliability Considerations, February 2017, http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf.
[120] NERC, *State of Reliability 2017* (Jun. 2017) at 2-3, http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/SOR_2017_MASTER_20170613.pdf.
[121] *Id.* at 24-25, 136.
[122] NERC Demand Response Availability Data System Working Group (DADSWG), *DADSWG Agenda*, June 28, 2017.
[123] NERC, *State of Reliability 2017* (Jun. 2017) at Appendix D, http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/SOR_2017_MASTER_20170613.pdf.
[124] *Id.* at 25.

# 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 incentive-based and time-based rate demand response programs in 2014 and 2015, and summarizes recent federal, regional, state, and industry demand response actions. Tables 5-1 and 5-2 present customer enrollments in incentive-based[125] and time-based[126] demand response programs for 2014 and 2015. Enrollment in these types of programs remains close to its highest level.

As shown in Table 5-1, in 2015, the number of customers enrolled in incentive-based demand response programs nationwide decreased by two percent to approximately 9.1 million customers, slightly below a high in 2014 of 9.3 million customers. On a regional basis, customer enrollment increased by nearly 60 percent in NPCC from 2014 to 2015, reaching almost 81,000 customers, although this total is still relatively small compared to other regions. According to EIA data, this increase was primarily due to higher reported enrollment in programs run by Con Edison, Green Mountain Power, and New Hampshire Electric Cooperative. Enrollment in WECC rose by 12 percent, or approximately 320,000 customers, due to higher reported enrollment in programs run by PG&E, City of Glendale, San Diego Gas & Electric (SDG&E), and PacifiCorp; these gains were offset by lower reported enrollment in SCE's programs, among others. In contrast, enrollment fell by more than 20 percent, or more than 420,000 customers, in RelibilityFirst due to large reported decreases in enrollment in programs run by Delmarva Power, PEPCO, Duke Energy Indiana, and Delaware Electric Cooperative. Likewise, enrollment in FRCC fell by 15 percent, or approximately 220,000 customers, primarily due to lower reported enrollment in programs run by Withlacoochee River Electric Cooperative.

[125] 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.
[126] 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.

**Table 5-1: Customer Enrollment in Incentive-based Demand Response Programs, by Region (2014 & 2015)**

| Region | Enrollment in Incentive-based Programs | | Year-on-Year Change | |
|---|---|---|---|---|
| | 2014 | 2015 | Customers | % |
| AK | 2,428 | 2,431 | 3 | 0% |
| FRCC | 1,490,073 | 1,271,487 | -218,586 | -15% |
| HI | 36,102 | 36,008 | -94 | 0% |
| MRO | 1,227,445 | 1,205,568 | -21,877 | -2% |
| NPCC | 51,227 | 80,884 | 29,657 | 58% |
| RF | 2,012,846 | 1,591,730 | -421,116 | -21% |
| SERC | 1,303,339 | 1,410,799 | 107,460 | 8% |
| SPP RE | 175,146 | 204,020 | 28,874 | 16% |
| Texas RE | 302,913 | 307,089 | 4,176 | 1% |
| WECC | 2,651,163 | 2,972,779 | 321,616 | 12% |
| Unspecified | 12,947 | 11,343 | -1,604 | -12% |
| **Total** | **9,265,629** | **9,094,138** | **-171,491** | **-2%** |

*Sources*: EIA, EIA-861 Demand_Response_2014, Utility_Data_2014, Demand_Response_2015, and Utility_Data_2015 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 below indicates, nationwide enrollment in time-based programs increased approximately 10 percent in 2015, continuing a trend since 2012. The bulk of this increase occurred in the ReliabilityFirst region, with almost 370,000 new customer enrollments, and the WECC region, with approximately 266,000 new customer enrollments. EIA data indicate the increase in time-based program enrollments for the ReliabilityFirst region is due to a significant increase in enrollment in existing residential programs run by Delmarva Power, Baltimore Gas & Electric, ComEd, and PEPCO. Taken together, the decrease in enrollment in Delmarva Power's and PEPCO's incentive-based programs, and the corresponding increase in these utilities' time-based program enrollment, may in part reflect a shift from one program type to the other.

The increase in enrollment for the WECC region is primarily due to significant enrollment increases in existing residential and commercial programs run by PG&E, and residential programs run by Salt River Project and SDG&E. In addition, Marin Clean Energy, a community choice aggregator, reported new program enrollment. In MRO, increased enrollment in the region primarily reflects a significant increase in reported enrollment in residential and commercial programs run by Otter Tail Power. In contrast, in Texas RE reported enrollment decreased significantly, as a result of TriEagle Energy no longer reporting participation in a residential program it had administered in 2014. Entities without a specified NERC region also reported growth in time-based customer participation, primarily reflecting an increase in residential time-based program enrollment for Family Energy, a New York power marketer.[127]

**Table 5-2: Customer Enrollment in Time-based Demand Response Programs, by Region (2014 & 2015)**

| Region | Enrollment in Time-based Programs 2014 | Enrollment in Time-based Programs 2015 | Year-on-Year Change Customers | Year-on-Year Change % |
|---|---|---|---|---|
| AK | 53 | 53 | 0 | 0% |
| FRCC | 20,069 | 21,444 | 1,375 | 7% |
| HI | 466 | 538 | 72 | 15% |
| MRO | 94,176 | 129,558 | 35,382 | 38% |
| NPCC | 252,323 | 262,030 | 9,707 | 4% |
| RF | 2,553,434 | 2,923,239 | 369,805 | 14% |
| SERC | 203,954 | 198,627 | -5,327 | -3% |
| SPP RE | 1,188,004 | 1,198,489 | 10,485 | 1% |
| Texas RE | 49,481 | 1,867 | -47,614 | -96% |
| WECC | 2,416,960 | 2,683,400 | 266,440 | 11% |
| Unspecified | 115,906 | 169,815 | 53,909 | 47% |
| **Total** | **6,894,826** | **7,589,060** | **694,234** | **10%** |

*Sources*: EIA, EIA-861 Dynamic_Pricing_2014 and Dynamic_Pricing_2015 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

Since the last staff report, the Commission issued several demand response-related orders. On October 17, 2016, the Commission approved PJM's proposed modifications to the measurement and verification of load reductions that occurred during emergency conditions in its Emergency Load Response Program.[128] These modifications included several changes to the use and application of customer baselines during these emergency periods. On February 3, 2017, the Commission granted a complaint filed by multiple parties (including the New York PSC) against NYISO. The Commission found that application of NYISO's buyer-side market power mitigation rules to demand response resources participating in NYISO's Special Case Resources (SCR) capacity program was unjust, unreasonable, unduly discriminatory or preferential because those demand response resources had limited or no incentive and ability to exercise buyer-side market power to artificially suppress capacity market prices.[129] On February 2, 2017, the Commission approved proposed changes to MISO's tariff to establish measurement and verification criteria for certain demand response resources called Load Modifying Resources for the purpose of determining whether these resources are meeting their performance obligations.[130]

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[127] 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, http://www.eia.gov/electricity/data/eia861/.
[128] *PJM Interconnection, L.L.C.*, 157 FERC ¶ 61,067 (2016).
[129] *New York Independent System Operator, Inc.*, 158 FERC ¶ 61,137 (2017).
[130] *Midcontinent Independent System Operator, Inc.*, 158 FERC ¶ 61,119 (2017).

As part of its acceptance, the Commission clarified that the proposal introduced no new measurement and verification criteria for resources that do not participate in MISO's resource adequacy determination process.

In addition, under delegated authority, Commission staff approved ISO-NE's proposal to remove from its tariff the two existing active demand response resource types (Real-Time Demand Response and Real-Time Emergency Generation), which had certain limitations on the services they were allowed to provide. All references to these two resource types will be removed from the tariff effective June 1, 2018, when demand response resources are proposed to be fully integrated into the ISO-NE markets.[131]

On April 11, 2016, the Commission issued identical data requests to each RTO/ISO, and a separate request for comments to the public, regarding the RTO/ISO market rules for electric storage resources.[132] In response to the information received from these data requests, the Commission issued a Notice of Proposed Rulemaking on November 17, 2016, proposing to amend its regulations under the Federal Power Act (FPA) to remove barriers to the participation of electric storage resources and distributed energy resource aggregations in the capacity, energy, and ancillary service markets operated by RTOs and ISOs (organized wholesale electric markets). Specifically, the Commission proposed to require each RTO and ISO to revise its tariff to: (1) establish a participation model consisting of market rules that, recognizing the physical and operational characteristics of electric storage resources, accommodates their participation in the organized wholesale electric markets; and (2) allow distributed energy resource aggregators, including electric storage resources, to participate directly in the organized wholesale electric markets.[133] Comments on the proposed rule were filed on February 13, 2017.

## Other federal demand response activities

### *U.S. Department of Defense*

In fiscal year 2016, the Department of Defense (DOD) used approximately 30 million MWh of electricity to operate its facilities, over 50 percent of the federal government's total.[134] The DOD's Defense Logistics Agency Energy's (DLA Energy) primary mission is to provide the DOD and other agencies with comprehensive energy solutions,[135] including administering incentive-based demand response programs. In fiscal year 2016, DLA Energy operated 68 demand response installations across all four branches of the military, the DOD, and other

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[131] *ISO New England Inc. and New England Power Pool Participants Committee*, Docket Nos. ER17-925-00 & ER17-925-001, at 1-2 (Mar. 15, 2017) (delegated letter order).
[132] *Electric Storage Participation in Regions with Organized Wholesale Electric Markets*, Docket No. AD16-20-000 (Apr. 11, 2016).
[133] *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 157 FERC ¶ 61,121 (2016).
[134] U.S. DOE, *Comprehensive Annual Energy Data and Sustainability Performance: Site-Delivered Energy Use by End-Use Sector and Energy Type in FY 2016 (Billion Btu)*, http://ctsedwweb.ee.doe.gov/Annual/Report/SiteDeliveredEnergyUseAndCostBySectorAndTypeAndFiscalYear.aspx.
[135] U.S. DOD, Defense Logistics Agency, *Fiscal Year 2016 Fact Book*, at 2, http://www.dla.mil/Portals/104/Documents/Energy/Publications/E_Fiscal2016FactBookWebResolution_170706.pdf.

federal civilian agencies in 16 states and the District of Columbia.[136] In that fiscal year, the 202.3 MW that DLA Energy enrolled in demand response programs netted $5.9 million in savings, while the demand response programs have accrued $34.2 million in savings since their inception in 2008.[137]

Individual initiatives within the DOD are also underway, namely at the Fort Hood Army base in Killeen, Texas, which hosts a vehicle-to-grid program with 14 electric vehicle charging stations that provides demand response, peak shaving and ancillary services in ERCOT's wholesale market.[138]

The development of renewable energy systems and potential for microgrids on military installations has created an incentive for the DOD's Environmental Security Technology Certification Program (ESTC Program) to develop programs for distributed resources to participate in energy markets through demand response and other means.[139] In February 2017, the ESTC Program issued a request for proposals[140] and held a webinar in April 2017 to develop solutions for the DOD's energy programs.[141] In addition, the ESTC Program is funding a project that is developing a method for direct, automated participation by DOD installations in demand response programs.[142] As part of this project, Camp Pendleton participated in Southern California's Capacity Bidding Program in 2017 and anticipates $67,000 in annual savings from 1 MW in reductions.[143]

### *U.S. General Services Administration*

The U.S. General Services Administration (GSA) provides the Federal government with workplaces by constructing, managing, and preserving government buildings and by leasing and managing commercial real estate. GSA continued to enable the participation of facilities it

[136] *Id.* at 54.

[137] *Id.*

[138] U.S. DOD, *Strategic Sustainability Performance Plan Fiscal Year 2016*, at 62, http://www.denix.osd.mil/sustainability/dod-sspp/unassigned/department-of-defense-strategic-sustainability-performance-plan-fy-2016/.

[139] U.S. DOD, Strategic Environmental Research and Development Program (SERDP) Environmental Security Technology Certification Program (ESTCP), *Internet of Things (IoT): Opportunities and Challenges for Implementation on DoD Installations*, https://www.serdp-estcp.org/News-and-Events/Blog/Internet-of-Things-IoT-Opportunities-and-Challenges-for-Implementation-on-DoD-Installations.

[140] U.S. DOD, Strategic Environmental Research and Development Program (SERDP) Environmental Security Technology Certification Program (ESTCP), *Installation Energy Solicitation*, https://www.serdp-estcp.org/Funding-Opportunities/ESTCP-Solicitations/Installation-Energy-Solicitation.

[141] U.S. DOD, Strategic Environmental Research and Development Program (SERDP) Environmental Security Technology Certification Program (ESTCP), *SERDP & ESTCP Webinar Series: Strategic Environmental Research and Development Program (SERDP) Environmental Security Technology Certification Program (ESTCP)*, https://www.serdp-estcp.org/Tools-and-Training/Webinar-Series/04-20-2017.

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

[143] U.S. DOD, Strategic Environmental Research and Development Program (SERDP) Environmental Security Technology Certification Program (ESTCP), *SERDP & ESTCP Webinar Series: Solutions for Installations' Participation in Energy Markets* (Apr. 20, 2017) at 55, https://www.serdp-estcp.org/Tools-and-Training/Webinar-Series/04-20-2017/Webinar-Slides-04-20-17.

manages in various demand response programs in 2016 and 2017. In April 2017, GSA announced that its Northeast and Caribbean Region demand response programs garnered $479,630 in annual rebates by participating in NYISO and PJM demand response programs.[144] Since 2011, the Northeast and Caribbean region's net earnings through its 17 federally-owned buildings participating in demand response programs has totaled $1.96 million.[145] The combined savings from existing demand response programs fund infrastructure updates, energy saving performance contracts, and new projects that generate revenue through participation in demand response.[146]

## Developments and issues in demand response

### *State legislative and regulatory activities related to demand response*

This section highlights developments in retail demand response and time-based pricing activities. In the past year, there has been movement towards further deployment of time-of-use rates, with continued progress in California and Colorado toward making time-of-use rates the default for residential customers. In addition, several states have conducted, or propose to conduct, studies to assess the potential for demand response to meet resource needs.

- **Arizona.** On September 1, 2017, Arizona Public Service Company (APS) filed an application with the Arizona Corporation Commission for approval of its 2018 Demand Side Management Plan. In its plan, APS proposes a number of measures, including a "reverse" (load increasing) demand response pilot, meant to reduce peak demand and shift load to mid-day in the non-summer months to allow better integration of solar on the grid. The reverse demand response pilot, which APS proposes to implement in 2018, would allow the utility to call on non-residential facilities to increase electricity demand during periods of negative prices due to over-generation. The pilot is intended to provide load flexibility and reduce the need to curtail solar generation. To be eligible, facilities must have a minimum demand of 30 kW. APS would provide participating facilities with the necessary sub-metering and telecommunications infrastructure, but would not provide an incentive payment. Instead, program participants would be allowed to use electricity at no cost during event periods. APS proposes to cap the budget at $200,000 in 2018.[147]

- **California.** In 2013, the CPUC established a rulemaking to enhance the role of demand response in meeting the state's resource planning needs and operational requirements.[148]

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[144] U.S. General Services Administration, *GSA Striking it Green for Taxpayers* (Aug. 2017), https://www.gsa.gov/portal/content/161982.
[145] *Id.*
[146] *Id.*
[147] *In The Matter Of The Application Of Arizona Public Service Company For A Ruling Relating To Its 2018 Demand Side Management Implementation Plan*, Docket No. E-01345A-17-0134 (Arizona Corporation Commission Sep. 1, 2017) Exhibit A at 19-20, http://docket.images.azcc.gov/0000182484.pdf.
[148] *Order Instituting Rulemaking To Enhance The Role Of Demand Response In Meeting The State's Resource Planning Needs And Operational Requirements*, Docket No. R.13-09-011 (CPUC Sep. 25, 2013); *Joint Assigned Commissioner And Administrative Law Judge Ruling And Scoping Memo*, Docket No. R.13-09-011 (CPUC Nov. 14, 2013).

In Decision 14-12-024, the CPUC provided guidance to the state's three investor-owned utilities (IOUs) concerning their demand response portfolios for 2018 and beyond, defining a set of principles for all demand response programs going forward.[149] In compliance with this order, in January 2017, SDG&E,[150] PG&E,[151] and SCE[152] submitted their 2018-2022 demand response proposals to the CPUC for approval.

The CPUC had previously required the IOUs to establish Demand Response Auction Mechanism (DRAM) pilots to test the viability of using a competitive mechanism to procure aggregated demand response resources to provide local, system and flexible capacity. Originally a two-year pilot, the DRAM was extended to a third phase.[153] Approximately 40 MW of demand response was procured in the first DRAM auction for 2016 delivery, and approximately 82 MW for 2017 delivery.[154] The CPUC Energy Division approved contracts resulting from the third auction, through which the three IOUs procured approximately 182 MW of demand response for August 2018 delivery and 189 MW for August 2019 delivery. Approximately a quarter of this is aggregated residential demand response.[155] On October 26, 2017, the CPUC issued a decision

[149] Among other things, the CPUC established that demand response should be flexible and reliable to support renewable integration and emissions reductions, should evolve to meet changing grid needs, should be procured from third parties in open markets, and should be dispatched pursuant to wholesale or distribution market instructions, superseded only for emergency conditions. See *Order Instituting Rulemaking to Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements*, Docket No. R.13-09-011 (CPUC Sep. 19, 2013) at 46, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M167/K725/167725665.PDF.

[150] *Application of San Diego Gas & Electric Company (U-902-E) Requesting Approval and Funding for 2018-2022 Demand Response Portfolio in compliance with Decision 16-09-056*, Application No. A.17-01 (CPUC Jan. 17, 2017), https://www.sdge.com/sites/default/files/regulatory/Application_of_SDGE_2018-2022_Demand_Response_with_attachments_COS.pdf.

[151] *Application of Pacific Gas and Electric Company (U 39-E) for Approval of Demand Response Programs, Pilots and Budgets for Program Years 2018-2022*, Application No. 17-01 (CPUC Jan. 17, 2017), http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M172/K519/172519506.PDF.

[152] *Application of Southern California Edison Company (U 338-E) for Approval of its 2018 – 2022 Demand Response Programs*, Application No. 17-01 (CPUC Jan. 17, 2017), http://www3.sce.com/sscc/law/dis/dbattach5e.nsf/0/76E43EB7170CC097882580AC000C9B49/$FILE/A1701XXX-SCE%202018-2022%20DR%20Application.pdf.

[153] *Order Instituting Rulemaking to Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements*, Docket No. R.13-09-011 (CPUC Jun. 9, 2016), http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M163/K467/163467479.PDF; *Resolution E-4817, Approval with Modifications to Southern California Edison Company, Pacific Gas and Electric Company, and San Diego Gas & Electric Company's Demand Response Auction Mechanism Pilot for 2018-2019*, (CPUC Jan. 19, 2017), http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M172/K765/172765001.PDF.

[154] Greentech Media, *California's DRAM Auction Contracts for 82MW of Distributed Energy as Grid Resource* (Aug. 3, 2016), https://www.greentechmedia.com/articles/read/californias-dram-auction-contracts-for-82mw-of-distributed-energy-as-grid-r.

[155] *Staff Disposition of: PG&E AL 5109-E- PG&E's 2018-2019 Demand Response Auction Purchase Agreements*, Advice Letter 5109-E (CPUC Energy Division Jun. 30, 2017), at 1, 10, https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_5109-E.pdf; *Staff Disposition of: SDG&E AL 3095-E-SDG&E's 2018-2019 Demand Response Auction (DRAM) Results*, Advice Letter 3095-E (CPUC Energy Division Jun. 30, 2017), http://regarchive.sdge.com/tm2/pdf/3095-E.pdf; *Staff Disposition of: SCE AL 3629-E – SCE's 2018-*

requiring an additional DRAM pilot auction to be held in the spring of 2018 for contracts for delivery in 2019.[156] To assess whether to make the DRAM permanent and the primary means of sourcing demand response in the state, the CPUC authorized its Energy Division staff to conduct an independent analysis of the results from the DRAM auctions, to be released no later than June 2018.[157]

Additionally, the CPUC approved PG&E's,[158] SCE's,[159] and SDG&E's[160] proposed residential time-of-use pilot programs, which were required under CPUC Decision 15-07-001. The proposed default time-of-use rates will begin in March 2018 and will have a peak period from 4 p.m. to 9 p.m., later in the day than has been the case historically.[161]

On March 1, 2017, Lawrence Berkeley National Laboratory (LBNL) released its final report on Phase II of its 2025 California Demand Response Potential Study, which was commissioned by the CPUC. It is the first study to evaluate the technical potential, hourly availability, and value relative to other resources, of demand response resources for the state's IOUs.[162] Based on customer load profiles developed from smart meter data in Phase I of the study, Phase II models the potential size and cost of the state's demand response resources in the future, presents a simplified taxonomy of demand response service types,[163] and considers non-traditional technologies.[164] A key finding is

*2019 Demand Response Auction (DRAM) Purchase Agreements*, Advice Letter 3629-E (CPUC Energy Division Jul. 7, 2017), https://www.sce.com/NR/sc3/tm2/pdf/3629-E.pdf.

156 *Order Instituting Rulemaking to Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements*, Docket No. R.13-09-011 (CPUC Oct. 26, 2017), http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M167/K725/167725665.PDF.

157 *Order Instituting Rulemaking to Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements*, Docket No. R.13-09-011 (CPUC Sep. 29, 2016) at 66-67, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M167/K725/167725665.PDF.

158 *Resolution E-4846: Adoption of Pacific Gas and Electric Company's residential default time-of-use pricing pilot pursuant to Decision 15-07-001* (CPUC Aug. 10, 2017), http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M191/K530/191530523.PDF.

159 *Resolution E-4847: Adoption of Southern California Edison's (SCE's) Residential Default Time-of-Use (TOU) Pilot with modifications* (CPUC May 11, 2017), http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M186/K711/186711908.PDF.

160 *Resolution E-4848: Adoption of San Diego Gas & Electric Company's residential default time-of-use pricing pilot pursuant to Decision 15-07-001* (CPUC May 25, 2017), http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M188/K449/188449503.PDF.

161 *Order Instituting Rulemaking to Assess Peak Electricity Usage Patterns and Consider Appropriate Time Periods for Future Time-of-Use Rates and Energy Resource Contract Payments*, Docket No. R.15-12-012 (CPUC Nov. 1, 2016), http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M169/K117/169117846.PDF.

162 Alstone, et al. (Lawrence Berkeley National Laboratory), *Final Report on Phase 2 Results: 2025 California Demand Response Potential Study: Charting California's Demand Response Future* (Mar. 1, 2017) at 2-9, http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442452698.

163 Service types include "Shape" (long-term changes to demand through time-varying pricing and behavior change), "Shift" (shifting load to non-peak times to reduce over-generation and net load ramps), "Shed" (temporarily curtailing load to provide peak capacity during system emergencies), and "Shimmy" (dynamically adjusting demand to provide load following and regulation service). *See id.* at 3-13 and 3-14.

164 In addition to the technologies traditionally used to provide demand response (industrial processes, commercial lighting, pool pumps, refrigerated warehouses, agricultural pumping, and wastewater processes), the study also considers behind-the-meter storage, electric vehicles, and data centers as potential sources of demand response.

that the role for traditional demand response resources (i.e., peak shaving) is declining in California, while the need for fast-responding, flexible loads that can provide time-differentiated and location-differentiated services, is growing.[165]

- **Colorado.** On November 9, 2016, the Colorado PUC approved a settlement agreement filed by Public Service Company of Colorado (PSCo) that resolved, among other things, its 2016 Electric Phase II rate proceeding. In this proceeding, PSCo proposed a new rate schedule incorporating, among other things, pilots of two optional time-of-use rates for residential customers and a critical peak pricing rate for commercial and industrial customers, starting in 2017. One of the residential rate options has three components: a monthly demand charge, a time-of-use component, and a charge for services and facilities. PSCo will use this rate to assess the effect of a demand charge on customer behavior and energy choices. The second residential time-of-use rate option includes replacing enrolled customers' meters with advanced meters to track their energy usage on a time-differentiated basis. PSCo must file an advice letter with the Colorado PUC no later than December 2, 2019 establishing this rate as permanent and mandatory for all residential customers, modifying the rate as necessary based on PSCo's analysis of the pilot results.[166] On March 15, 2017, the Colorado PUC opened a new proceeding to serve as a repository for information related to the new pilot rate options.[167]

- **Hawaii.** The Hawaii PUC approved the HECO Companies' Power Supply Improvement Plan Update on July 17, 2017. The plan forecasts close to 115 MW of demand response resources being available by 2021, as part of HECO Companies' path to meeting the state's 100 percent Renewable Portfolio Standard by 2045. HECO Companies' proposed demand response portfolio includes nine demand response programs providing multiple grid services.[168] HECO Companies also predict that electrification of transportation could create new opportunities for demand response to offset utility investments in storage or generation that would otherwise be needed.[169]

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[165] Alstone, et al. (Lawrence Berkeley National Laboratory), *Final Report on Phase 2 Results: 2025 California Demand Response Potential Study: Charting California's Demand Response Future* (Mar. 1, 2017), at 1-11, 2-4, 6-3, http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442452698.

[166] *In The Matter Of Advice Letter No. 1712 Filed By Public Service Company Of Colorado To Revise Electric Base Rates And Changes To Tariff Sheets And Replace PUC No. 7 With PUC No. 8 To Become Effective February 25, 2016*, et al., Proceeding Nos. 16AL-0048E, 16A-0055E, and 16A-0139E (Colorado PUC Nov. 9, 2016), http://www.dora.state.co.us/pls/efi/EFI_Search_UI.Show_Decision?p_session_id=&p_dec=23626.

[167] *In The Matter Of The Commission's Review Of The Residential Time-Of-Use Trial And Demand Rate Pilot Implemented By Public Service Company Of Colorado*, Proceeding No. 17M-0204E (Colorado PUC Mar. 15, 2017), http://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=861299.

[168] These include real-time pricing, and time-of-use, day-ahead load shift, minimum load, PV curtailment, and critical peak incentive programs to provide capacity; a fast frequency response program; a regulating reserve program to provide regulation up; and non-spin auto response program to provide 10-minute supplemental reserves. *See 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).

[169] *Hawaiian Electric Companies Power Supply Improvement Plan Update Report -- Book 1*, Dec. 23, 2016, at ES-7, https://www.hawaiianelectric.com/Documents/about_us/our_vision/psip_executive_summary_20161223.pdf.

Delays in HECO Companies' demand response implementation timeline have led to postponement of the planned rollout of its Demand Response Management System (DRMS) software until Hawaii PUC approves the timeline. This timeline had established milestones for HECO Companies' integration of its demand response portfolio with an original deadline for DRMS integration of December 1, 2017.[170]

Additionally, Maui Electric Company received approval to expand their Fast Demand Response Program to 5.0 MW. The termination of Hawaiian Commercial and Sugar's power purchase agreement, which supplied six percent of Maui's annual electricity, created a need for these additional resources. The Fast Demand Response Program utilizes a peak time rebate with event notices indicating requested reductions, and requires 10-minute response times.[171]

- **Massachusetts/Rhode Island.** National Grid has partnered with curtailment service providers CPower, EnerNOC, and IPKeys to offer its first demand response program to commercial customers in Massachusetts and Rhode Island. Customers who enroll in the program are paid $20 per kW and $0.75 per kWh reduced during events. Electric storage resources are eligible to participate.[172]

- **Michigan.** In December 2016, Michigan's governor signed Public Acts 341 and 342, which require, among other things, a statewide demand response potential study, as well as the promotion of load management programs as part of a new integrated resource planning process and energy waste reduction efforts.[173] Partially in response to this new legislation, in May 2017, the Michigan Public Service Commission (Michigan PSC) directed its staff to convene a workgroup tasked with proposing a framework for the evaluation and cost recovery of demand response investments, which the Michigan PSC previously had found were not well served by traditional rate setting processes.[174] On August 24, 2017, Michigan PSC staff issued a set of options regarding planning and cost recovery of demand response programs for the Michigan PSC to consider. Of these options, Michigan PSC staff recommended a "three phase plan" in which demand response resources would be evaluated alongside traditional supply resources in integrated resource planning proceedings and cost recovery for these programs would be determined in general rate cases, with an annual reconciliation mechanism to align the two processes.[175] The demand response potential study, completed at the end of

[170] *Status Update to the Demand Response Portfolio Implementation Update*, Docket Nos. 2015-0411 and 2015-0412 (Hawaii PUC Jul. 12, 2017).
[171] *For Approval of Expansion of Fast Demand Response Pilot Program and Recovery of Program Costs*, Docket No. 2016-0232 (Hawaii PUC Jul. 17, 2017).
[172] National Grid, *Participate in Demand Response, save energy, and receive incentives!*, https://www.nationalgridus.com/media/pdfs/bus-ways-to-save/connectedsolution-ma-ci-dr-info-flier.pdf.
[173] Michigan PSC, *Energy Law Updates*, http://www.michigan.gov/mpsc/0,4639,7-159-80741---,00.html.
[174] *In the matter, on the Commission's own motion, initiating a process to address demand response issues for regulated electric utilities*, Case No. U-18369 (Michigan PSC May 11, 2017), http://efile.mpsc.state.mi.us/efile/docs/18369/0001.pdf.
[175] *In the matter, on the Commission's own motion, initiating a process to address demand response issues for regulated electric utilities, Staff Demand Response Regulatory Framework Recommendations*, Case No. U-18369 (Michigan PSC Staff Aug. 24, 2017), http://efile.mpsc.state.mi.us/efile/docs/18369/0011.pdf.

September 2017, estimated a realistic achievable potential of 265-849 MW annually in 2018, rising to 1.3-2.2 GW annually by 2037. More than half of this potential is estimated to come from residential customers participating in dynamic pricing programs.[176]

- **New Mexico**. On February 22, 2017, the New Mexico PRC approved El Paso Electric Company's application to implement a demand response pilot program. The three-year pilot will run in the summer months only, and is limited to 3,000 residential and small commercial customers with central air conditioning and an eligible smart thermostat provided and installed by the customer. Participants will receive a $125 enrollment incentive and a $25 annual participation incentive to allow El Paso Electric to remotely control their thermostat during periods of peak demand.[177]

- **New York.** On March 9, 2017, as part of New York's Reforming the Energy Vision initiative, the New York PSC released an Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters.[178] According to the New York PSC, this order is part of the effort to coordinate a transition from net energy metering to valuing customer, electric system, and societal benefits, and increasing the granularity of value assessment. New values are defined by four categories: energy value, capacity value, environmental value, and demand reduction value. While Phase I of the program does not include demand response due to preexisting tariffs, the New York PSC indicates that this "value stack" compensation will be expanded in Phase II to include all distributed energy resources, including demand response as defined within the order, as soon as possible.[179] An organizational conference was held on May 23, 2017 to address the scope of the proposed expanded tariff, and a deadline of the end of 2018 has been established for its publication.[180]

- **Texas.** Pursuant to HB 4097, enacted in 2015, ERCOT released a study at the end of 2016 investigating the potential for desalination projects to participate as demand response resources in the ERCOT market. The report notes that seawater desalination is an energy-intensive process that removes salt and other minerals from seawater to produce freshwater for municipal consumption, and that participation in demand response could help mitigate electricity costs for future desalination projects in the state while

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[176] Applied Energy Group *State of Michigan Demand Response Potential Study* (Sep. 2017), at v-vi, 46-48, prepared for the State of Michigan, http://www.michigan.gov/documents/mpsc/State_of_Michigan_-_Demand_Response_Potential_Report_-_Final_29sep2017__602435_7.pdf.

[177] New Mexico PRC, *Commission Grants EPE's Application for Demand Response Pilot Program* (Feb. 23, 2017), http://www.nmnn.net/press/PRC022317.pdf.

[178] *In the Matter of the Value of Distributed Energy Resources*, et al., Case Nos. 15-E-0751 and 15-E-0082, (New York PSC Mar. 9, 2017), http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={FD2886CF-87D6-4F02-A252-95F9094A2CED}.

[179] *Id.* at 44.

[180] *In the Matter of the Value of Distributed Energy Resources, et al.*, Case Nos. 15-E-0751 and 15-E-0082 (New York PSC Mar. 9, 2017), at 136, http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={FD2886CF-87D6-4F02-A252-95F9094A2CED}.

providing reliability benefits to the grid. The study looked at the two main demand response reliability-based services in ERCOT,[181] finding that desalination plants can meet the qualification requirements for either service, depending on plant design (which determines response time, recovery time, demand predictability, and operational flexibility). As such, ERCOT's study recommends that desalination project developers consider whether they will participate in demand response early in the project planning stages.[182]

In addition, on March 21, 2017, El Paso Electric filed an application for approval of a demand response pilot for residential and commercial customers similar to the pilot earlier approved in New Mexico (discussed above).[183]

- **Utah.** On June 28, 2017, the Utah Public Service Commission (Utah PSC) approved PacifiCorp's proposed Electric Vehicle Time-of-Use pilot program and an associated study of customer response to time-varying prices under the proposed rates. PacifiCorp proposed two time-of-use rate options with different spreads between on-peak and off-peak prices (3:1 and 10:1). The Utah PSC approved both rate options proposed by PacifiCorp, but did not approve an alternative proposed by other parties that would have included both time-of-use and inclining tiers.[184] The pilot program is part of the implementation of PacifiCorp's Sustainable Transportation and Energy Plan, which was authorized under a law adopted in 2016 allowing funding for electric vehicle infrastructure, battery storage, clean coal, and other programs.[185]

- **Virginia.** On June 1, 2017, the Virginia State Corporation Commission approved Dominion Energy Virginia's petition to allow the small number of customers participating in an existing dynamic pricing pilot to remain on these rates after the planned conclusion of the pilot on July 31, 2017.[186]

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[181] The two services are Responsive Reserve Service in the ancillary service market and Emergency Response Service.

[182] ERCOT, *Demand Response Potential for Seawater Desalination Projects* (Nov. 18, 2016), http://www.puc.texas.gov/industry/electric/reports/scope/2017/2017scope_elec.pdf.

[183] *El Paso Electric Company's Amendment to 2016 Energy Efficiency Plan for Pilot Program*, Docket No. 46967 (PUCT Mar. 21, 2017), http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/46967_1_933336.PDF.

[184] *In the Matter of the Application of Rocky Mountain Power to Implement Programs Authorized by the Sustainable Transportation and Energy Plan Act*, Docket No. 16-035-36 (Utah PSC Jun. 28, 2017), https://pscdocs.utah.gov/electric/16docs/1603536/2949541603536ptrao6-28-2017.pdf.

[185] State of Utah, *Sustainable Transportation and Energy Plan Act*, https://le.utah.gov/~2016/bills/sbillenr/SB0115.htm.

[186] *In Re: Virginia Electric and Power Company's proposed pilot program on dynamic rates*, Case No. PUE-2010-00135 (Virginia SCC Jun. 1, 2017), http://www.scc.virginia.gov/docketsearch/DOCS/3f%23901!.PDF.

### *Collaborative industry-government efforts*

In 2017, NAESB ratified two recommendations related to demand-side management and energy efficiency that created new retail demand response business standards.[187] On April 17, 2017, NAESB members approved Book 27 – Enrollment, Drop and Account Information Change for Demand Response Programs in a Registration Agent Marketplace, which focuses on the processes for a demand response service provider to enroll or drop a retail customer from their demand response program.[188] On July 9, 2017, NAESB members approved Book 28 – Self-Deployment of a Demand Response Program by a Demand Response Service Provider in a Registration Agent Model, which deals with a broad variety of interactions among retail customers, distribution companies, demand response service providers, and registration agents.[189]

[187] NAESB, *NAESB Bulletin*: *March – July 2017*, Vol. 10, Issue, 1, at 3, https://naesb.org//pdf4/naesb_bulletin_vol10_issue1.pdf.
[188] NAESB, Quadrant Executive Committee Meeting Announcements & Agendas- Highlighted with Additional Materials and Agenda Updates, https://www.naesb.org/pdf4/ec022117a.docx.
[189] NAESB, *NAESB Bulletin: March – July 2017*, Vol. 10, Issue 1, at 3.

# 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,[190] and previous annual staff reports, describe the barriers to customer participation in demand response. Outstanding barriers and recent actions taken to address them are presented below.

- **Implementing Time-based Pricing.** As noted above, enrollment in time-based demand response programs increased significantly in 2015 (the latest year with complete data), continuing a trend since 2012. More recently, according to the Brattle Group, a consulting firm, utilities and regulatory bodies around the globe are experimenting with an increasing number of pricing options as they contemplate retail rate reform brought on by changes in the electricity industry. Pricing options being considered and tested include time-based rates (time-of-use rates and various types of dynamic pricing), and customer and demand charges, among others. In the U.S., some growth in existing time-based rate programs has occurred: enrollment in Oklahoma Gas and Electric's variable peak pricing program has grown to 130,000 customers, whose average peak load has dropped 40 percent.[191] In addition, enrollment in Baltimore Gas & Electric's residential time-based rate program surpassed 1,000,000 customers in 2015,[192] and program participants realized an average demand reduction of approximately 16 percent in the same year.[193]

  In the last year, as noted elsewhere in this staff report, several state commissions have approved small-scale pilots of time-based rates. Other commissions are going further. For example, the CPUC is requiring the state's investor-owned utilities to implement residential default time-of-use rates by 2019.[194] In mid-2017, the CPUC approved the utilities' proposals for residential time-of-use pilot programs, as a means of testing the plans prior to full implementation in 2019.[195] The Colorado PUC also approved a pilot

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[190] FERC, *A National Assessment of Demand Response Potential* (2009), http://www.ferc.gov/legal/staff-reports/06-09-demand-response.pdf.
[191] Faruqui, A. and Lessem, N. (The Brattle Group), *A Global Survey of Customer-Centric Tariff Reforms*, presented to Commerce Commission Wellington, New Zealand (Aug. 24, 2017) at 7, 9, http://www.brattle.com/system/publications/pdfs/000/005/490/original/A_Global_Survey_of_Customer-centric_Tariff_Reforms.pdf?1504111043.
[192] EIA, EIA-861 Dynamic_Pricing_2015 data file, https://www.eia.gov/electricity/data/eia861/.
[193] Faruqui, A. and Lessem, N. (The Brattle Group), *A Global Survey of Customer-Centric Tariff Reforms*, presented to Commerce Commission Wellington, New Zealand (Aug. 24, 2017) at 10, http://www.brattle.com/system/publications/pdfs/000/005/490/original/A_Global_Survey_of_Customer-centric_Tariff_Reforms.pdf?1504111043.
[194] *Order Instituting Rulemaking on the Commission's Own Motion to Conduct a Comprehensive Examination of Investor Owned Electric Utilities' Residential Rate Structures, the Transition to Time Varying and Dynamic Rates, and Other Statutory Obligations*, Docket R.12-06-013, (CPUC Jul. 3, 2015), http://docs.cpuc.ca.gov/publisheddocs/published/g000/m153/k110/153110321.pdf.
[195] *See supra* notes 158, 159, and 160.

rate scheme in anticipation of moving to default residential time-of-use rates in the future.[196]

However, the Brattle Group notes that barriers remain to the wide-spread uptake of time-based rates. These include the need to understand how customer bills will change as rates are redesigned, to simulate how customers may react to bills based on rate changes, and to engage in direct customer outreach to explain why rates are changing. In addition, a gradual transition to the new tariffs—with an opt-out for certain populations—and appropriately designed pilots to test customer response, may ease the transition.[197]

- **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. Some states have taken action to coordinate state retail demand response programs with organized markets so that programs at the retail and wholesale levels are complementary. For example, as discussed above, the CPUC required California's three IOUs to establish Demand Response Auction Mechanism pilots to test the viability of using a competitive mechanism to procure aggregated demand response resources outside of utility programs, in order to provide local, system and flexible capacity. Participation in CAISO's two demand response products has also grown significantly over the past three years.[198] The CPUC's goal is to integrate all supply-side demand into CAISO wholesale markets by 2018. In addition, the CPUC held a series of workshops in early 2017 to identify policy issues related to the new model of demand response outlined in the state's demand response potential study, and to identify remaining barriers to the integration of demand response into the CAISO market.[199] The CPUC subsequently issued a decision that, among other things, established two new working groups to address the identified barriers and to integrate new models of demand response into the CAISO market.[200]

- **Demand Response as a Distribution System Resource.** Demand response has traditionally been used to address operational and planning needs on the bulk power (i.e., transmission) system. The growth of distributed energy resources (such as solar PV) and efforts to modernize U.S. electric grid infrastructure, have spurred interest in considering how demand response and other non-traditional resources may be used to address reliability needs on the distribution system. For instance, a survey conducted by the

[196] *See supra* note 166.
[197] Faruqui, M. (The Brattle Group), *Moving forward with tariff rate reform*, presented to EEI Webinar on Rate Design (Apr. 6, 2017), at 13-14, http://www.brattle.com/system/publications/pdfs/000/005/423/original/Moving_forward_with_tariff_reform.pdf?1491590325.
[198] In 2016, proxy demand response (PDR) capacity totaled 160 MW and reliability demand response resource (RDRR) capacity was 1,320MW. *See* CAISO, *2016 Annual Report on Market Issues and Performance* (2017) at 30-31, http://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf.
[199] *Administrative Law Judge's Ruling Requesting Responses To Questions Regarding The Pathway To New Models Of Demand Response, Implementation Of The Competitive Neutrality Cost Causation Principle, And Remaining Barriers To The Integration Of Demand Response Into the CAISO Market*, Docket No. R.13-09-011 (CPUC May 22, 2017), http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M187/K328/187328217.PDF.
[200] *Order Instituting Rulemaking to Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements*, Docket No. R.13-09-011 (CPUC Sep. 15, 2017).

Smart Electric Power Alliance and Navigant notes that 10 percent of utility survey respondents are already using demand response to provide "non-wires grid upgrades" on targeted distribution circuits, and that another 60 percent are planning, researching, or considering such use.[201]

Barriers to the use of demand response as a distribution system resource include the need to determine what services it can provide to the distribution grid, and the need to put a value on those services. A study by LBNL identifies a set of system requirements that distribution system operators monitor and manage to safely and reliably operate the distribution grid; these include maximum capacity relief, emergency load transfer, steady state voltage management, power quality, phase balancing, and outage recovery.[202] Demand response programs designed to meet bulk power system needs may have a limited ability to meet this set of distribution system requirements. For example, requiring "all or nothing" rather than partial dispatch of resources based on location, and using peak periods that do not necessarily coincide with the timing of primary or secondary distribution feeder maximum demand may not allow demand response resources to provide value to the distribution system where and when they are most needed.[203] LBNL's research suggests that re-designing demand response programs to allow for resource dispatch that is more targeted to prevailing system needs—such as through location-differentiated incentives or program enrollment—may increase the value of demand response to the distribution system.[204] Distribution system prices that vary by location may also allow more targeted demand response. Furthermore, to take advantage of some types of demand response programs to manage power quality and phase balancing, investments in new sensing technologies and inverter load controls may be necessary.[205] However, tweaking demand response programs to better meet the needs of the distribution system has the potential to affect the operation of the bulk power system, suggesting that greater coordination between the operators of the distribution and bulk power systems may be beneficial.

[201] Smart Electric Power Alliance, *2017 Utility Demand Response Market Snapshot* (Oct. 2017), at 6, 42, https://sepapower.org/resource/2017-utility-demand-response-market-snapshot/.
[202] Cappers et al. (LBNL), *Future Opportunities and Challenges with Using Demand Response as a Resource in Distribution System Operation and Planning Activities*, LBNL-1003951 (2016) at 4-6, https://emp.lbl.gov/sites/all/files/lbnl-1003951.pdf.
[203] *Id.* at 15-17.
[204] *Id.* at 17-19.
[205] *Id.* at 19-20.

*Assessment of*

# Demand Response AND Advanced Metering

*Federal Energy Regulatory Commission Staff Report*