2019 Assessment of

Demand Response and Advanced Metering

Staff Report
Federal Energy Regulatory Commission
December 2019

2019 Assessment of

Demand Response and Advanced Metering

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

Staff Report

December 2019

FEDERAL ENERGY REGULATORY COMMISSION

Neil Chatterjee, Chairman

Richard Glick, Commissioner

Bernard McNamee, Commissioner

ACKNOWLEDGEMENTS

Federal Energy Regulatory Commission Staff Team

Ben Foster, Team Lead
Timothy Bialecki
David Burns
David Kathan
Michael P. Lee
Samin Peirovi

Table of contents

List of tables & figures

I. Introduction

This report is the Federal Energy Regulatory Commission staff's (Commission staff's) fourteenth annual report on demand response and advanced metering required by section 1252(e)(3) of the Energy Policy Act of 2005 (EPAct 2005). The information presented in the report is based on publicly-available data and discussions with industry experts. The report uses this data to estimate demand response potential in the retail and wholesale markets; it generally[1] does not discuss the actual deployment or dispatch of demand response. The report contains no policy recommendations or conclusions.

Highlights of the report include the following:

- Advanced meters[2] are the most prevalent type of metering deployed throughout the country, accounting for more than half of all meters installed and operational in the United States. According to the Energy Information Administration (EIA),[3] 78.9 million advanced meters were operational nationwide in 2017 out of a total of 152.1 million meters, indicating a 51.9 percent penetration rate.
- Since the last report was published, electric utilities in a wide variety of states – such as Arkansas, Hawaii, Indiana, Minnesota, and New Jersey – have received approval for, or proposed, advanced meter deployment programs. Among other things, these programs aim to improve customer engagement, limit the frequency and duration of outages, and establish a foundation for other grid modernization activities.
- State regulators across the country largely appear to support advanced meter investments, with regulators in some states – including Hawaii and Virginia – requiring that electric utility program proposals include detailed program design, implementation, and customer engagement components in order to capture the full benefits of advanced meters. State regulators in New York and North Carolina have directed electric utilities to expand time-based rate offerings in an effort to reduce peak demand, leverage advanced meter investments, and account for an increasing proliferation of distributed energy resources, including electric vehicles and behind-the-meter battery storage systems. Regulators in states and jurisdictions such as Maryland, Michigan, Minnesota, and the District of Columbia have

[1] Chapter 3 does discuss deployment of emergency demand response in the wholesale markets in 2019.

[2] As defined by the Energy Information Administration (EIA), advanced metering infrastructure (AMI) meters (also referred to throughout this report as "advanced meters") are "[m]eters 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." Other types of meters currently in use – such as standard electromechanical, standard solid state, and automated meter reading (AMR) meters – are not considered advanced meters for the purposes of this report. *See* EIA, Form EIA-861: Annual Electric Power Industry Report Instructions, at 18, http://www.eia.gov/survey/form/eia_861/instructions.pdf.

[3] EIA, Form EIA-861 Advanced_Meters_2016 data file (re-released Jan. 15, 2019).

shown a particular interest in establishing time-based rates for electric vehicles in order to incentivize charging during off-peak periods. Of note, electric utilities in Missouri have been approved to implement new demand response programs for residential customers. Oregon electric utilities proposed similar programs.

- Overall demand response participation in the wholesale markets increased by approximately eight percent from 2017 to 2018, to a total of 29,674 megawatts (MW). On a regional basis, participation increased most in California ISO (CAISO) and Midcontinent Independent System Operator (MISO), while participation decreased most in ISO New England (ISO-NE). The participation (i.e., registration) of demand response in the wholesale capacity, energy, and ancillary services markets increased to six percent of peak demand in 2018.

This 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).

II. 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 Figure 2-1, the number of advanced meters in operation continues to increase, and advanced meters are the most prevalent type of metering deployed in the United States. This is seen across several data sets.

Table 2-1: Estimates of Advanced Meter Penetration Rates

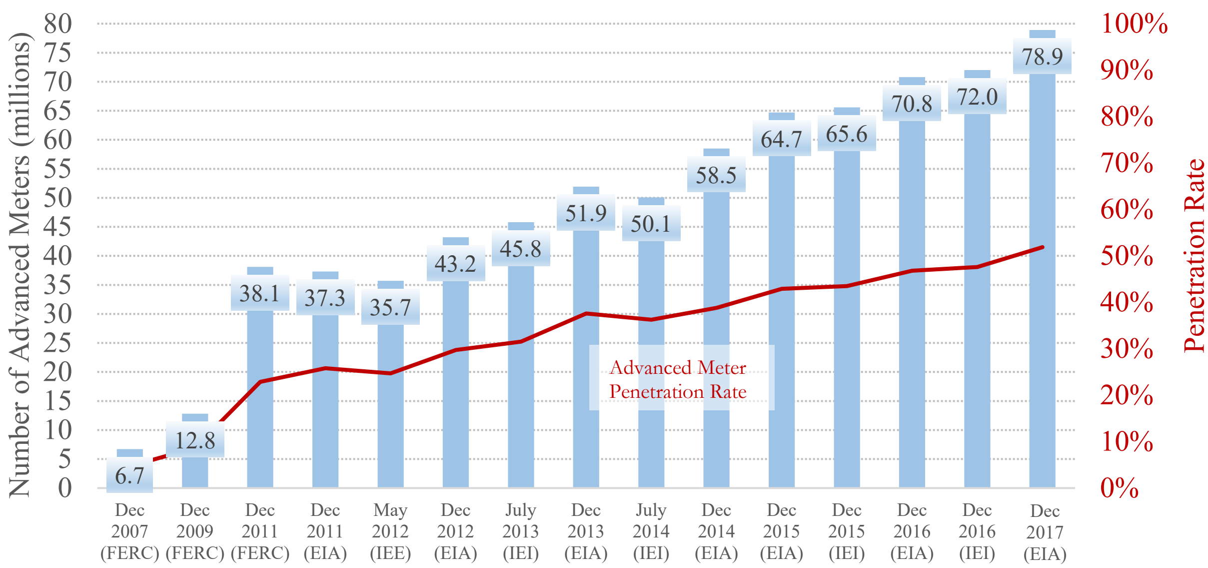
Data Source	Data As Of	Number of Advanced Meters (millions)	Total Number of Meters (millions)	Advanced Meter Penetration Rate
2008 FERC Survey	Dec 2007	6.7 [1]	144.4 [1]	4.7%
2010 FERC Survey	Dec 2009	12.8 [2]	147.8 [2]	8.7%
2012 FERC Survey	Dec 2011	38.1 [3]	166.5 [3]	22.9%
2011 Form EIA-861	Dec 2011	37.3 [4]	144.5 [4]	25.8%
Institute for Electric Efficiency	May 2012	35.7 [5]	144.5 [5]	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 [7]	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 [9]	36.3%
2014 Form EIA-861	Dec 2014	58.5 [10]	144.3 [10]	38.8%
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 [12]	43.5%
2016 Form EIA-861	Dec 2016	70.8 [13]	151.3 [13]	46.8%
Institute for Electric Innovation	Dec 2016	72.0 [14]	151.3 [14]	47.6%
2017 Form EIA-861	Dec 2017	78.9 [15]	152.1 [15]	51.9%

Sources: [1] FERC, *Assessment of Demand Response and Advanced Metering staff report* ("Staff Report" 2008). [2] FERC, *Staff Report* 2011. [3] FERC, *Staff Report* 2012. [4] 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 (IEE), *Utility-Scale Smart Meter Deployments, Plans & Proposals* (2012). [6] EIA-861 and EIA-861S: retail_sales_2012 and advanced_meters_2012 data files (Oct. 29, 2013). [7] The Edison Foundation Institute for Electric Innovation (IEI), *Utility-Scale Smart Meter Deployments: A Foundation for Expanded Grid Benefits* (2013). [8] EIA-861: Advanced_Meters_2013 data file (re-released Jun. 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* source note 4 above and *Form EIA-861 Annual Electric Power Industry Report Instructions*, Schedule 6, Part D, http://www.eia.gov/survey/form/eia_861/proposed/2013/instructions.pdf. [9] IEI, *Utility-Scale Smart Meter Deployments: Building Block Of The Evolving Power Grid* (2014). [10] EIA-861: Advanced_Meters_2014 data file (re-released Jan. 13, 2016). [11] EIA-861: Advanced_Meters_2015 data file (re-released Nov. 1, 2016). [12] IEI, *Electric Company Smart Meter Deployments: Foundation for A Smart Grid* (2016). EIA-861: Advanced_Meters_2016 data file (re-released Nov. 6, 2017). [14] IEI, *Electric Company Smart Meter Deployments: Foundation for a Smart Grid* (2017). [15] EIA-861: Advanced_Meters_2017 data file (re-released Jan. 15, 2019).

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 2017 EIA data,[4] 78.9 million advanced meters were operational out of a total of 152.1 million meters nationwide, representing a 51.9 percent penetration rate and an increase of approximately five percentage points from 2016 to 2017. Advanced meters now account for more than half of all meters in operation in the United States. Data from the Edison Foundation show similar figures for the number and penetration rate of advanced meters. Figure 2-1 shows the growth of advanced meters over time. Between 2007–2017, the number of advanced meters in operation has increased almost twelve-fold.

Figure 2-1: Advanced Meter Growth (2007–2017)



Note: years with more than one bar reflect data from multiple sources.

Table 2-2 provides estimated advanced meter penetration rates by North American Electric Reliability Corporation (NERC) region, as well as Alaska and Hawaii,[5] and by retail customer class. As previously stated, advanced meters now comprise the majority of all meters nationwide. Advanced meters also represent more than half of all meters in five of the eight NERC regions: approximately 90 percent of meters in Texas RE, 63 percent in SPP RE, 61 percent in WECC, 58 percent in FRCC, and 55 percent in ReliabilityFirst. The largest absolute growth in advanced meters from 2016 to 2017 occurred in ReliabilityFirst and SERC, where over 3.9 million and 1.8 million additional advanced meters, respectively, went into operation. The highest percentage growth in

[4] EIA, Form EIA-861: Advanced_Meters_2018 data file (re-released Jan. 15, 2019).

[5] For the time period examined (i.e., through the end of 2017), NERC comprised 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). The states of Alaska and Hawaii are not subject to NERC oversight. Note that, with the dissolution of SPP RE and FRCC in 2018 and 2019, respectively, there are currently six NERC Regional Entities. *See* Appendix and NERC, "NERC Regions Map," https://www.nerc.com/AboutNERC/keyplayers/PublishingImages/New%20Regions%20map%20no%20FRCC.jpg.

advanced meters took place in Alaska, with an increase of about 49 percent; ReliabilityFirst, with an increase of about 26 percent; MRO, with an increase of about 17 percent; and SERC, with an increase of about 14 percent.

Table 2-2 indicates that, nationwide, advanced meters are slightly more common among residential and commercial sectors compared to the industrial sector. In 2017, advanced meters accounted for approximately 52 percent of all residential meters, 50 percent of all commercial meters, and 44 percent of all industrial meters. Within regions, there is noticeable variation in advanced meter penetration by customer class. For example, for most regions (i.e., Alaska, ReliabilityFirst, SERC, SPP RE, Texas RE, and WECC), the residential sector has a higher rate of advanced meter penetration than the commercial or industrial sector. In contrast, in FRCC, Hawaii, MRO, and NPCC, advanced meter penetration is highest in the industrial sector. In 2017, the estimated advanced meter penetration rates for residential and commercial customer classes were greater than or equal to 50 percent for the first time, while the penetration rate for the industrial customer class increased to 44.5 percent.

Table 2-2: Advanced Meter Penetration Rate, by Customer Class and Region (2017)

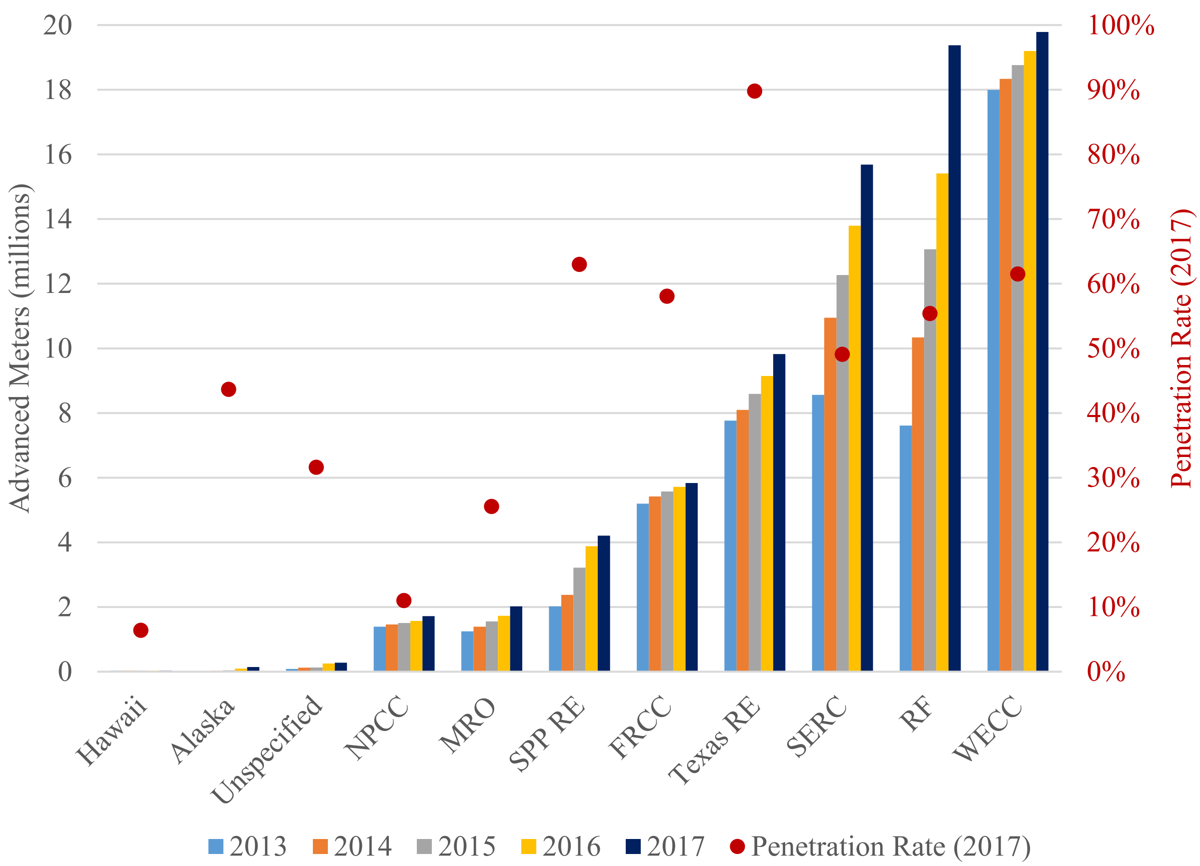
Region	Customer Class			
	Residential	Commercial	Industrial	All Classes
Alaska	46.0%	31.4%	11.4%	43.6%
FRCC	57.4%	62.4%	72.2%	58.0%
Hawaii	6.2%	7.6%	16.3%	6.4%
MRO	25.9%	21.4%	39.5%	25.5%
NPCC	10.9%	11.1%	18.8%	11.0%
ReliabilityFirst	55.8%	52.0%	41.9%	55.4%
SERC	49.7%	45.3%	39.0%	49.1%
SPP RE	63.7%	59.6%	56.1%	63.0%
Texas RE	90.7%	85.6%	39.6%	89.8%
WECC	61.8%	60.3%	47.3%	61.5%
Unspecified	31.8%	30.4%	23.9%	31.6%
All Regions	**52.2%**	**50.0%**	**44.5%**	**51.9%**

Sources: EIA, 2017 Form EIA-861 Advanced_Meters_2017 data file.

Note: The transportation sector data collected by EIA contain a relatively small number of meters and are not reported separately 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.

Figure 2-2, below, presents the increases in the number of advanced meters in all NERC regions from 2013 to 2017, and indicates that all regions experienced year-on-year growth for advanced meters. Since 2013, ReliabilityFirst experienced the most incremental growth, and WECC continues to have the largest number of installed and operational advanced meters, the majority of which are in California. For 2017, both WECC and ReliabilityFirst reported over 19 million advanced meters in operation. For the last two years of available data (2016 and 2017), large increases in the total number of advanced meters were seen in ReliabilityFirst and SERC, a continuation of the overall trend seen since 2013 in these regions. Similarly, Alaska and ReliabilityFirst experienced the greatest annual percentage increases from 2016 to 2017.

Figure 2-2: Number of Advanced Meters, by Region (2013–2017)



Developments and issues in advanced metering

State legislative and regulatory activity related to advanced metering

Since the last report was published, electric utilities in a wide variety of states have received approval for, or proposed, advanced meter deployment programs to, among other things, improve customer engagement,[6] limit the frequency and duration of outages, and establish a foundation for other grid modernization activities. State regulators across the country largely appear to support advanced

[6] With respect to advanced meters, customer engagement generally refers to efforts to ensure utility customers are aware of advanced meter deployments and the benefits of advanced meters. *See, e.g.,* DOE, *Voices of Experience: Insights on Smart Grid Customer Engagement*, at 4, https://www.smartgrid.gov/files/VoicesofExperience_Brochure_9.26.2013.pdf.

meter investments, with regulators in some states requiring that electric utility program proposals include detailed program design, implementation, and customer engagement components in order to capture the full benefits of advanced meters. Electric utilities have noted a concern that vendors may stop supporting automated meter reading (AMR) and other non-advanced meter functions in the near future, and they have asked state regulators to fully consider the costs of allowing customers to opt out of advanced meter programs. In states that have adopted aggressive renewable portfolio standards, regulators and utilities appear to agree that full advanced meter deployment will be essential to achieving clean energy goals in a cost-effective manner. The following section provides details of these activities.

- **Arkansas**. On December 7, 2018, the Arkansas Public Service Commission (Arkansas PSC) approved a customer education plan for the largest utility in the state, Entergy Arkansas, to support the deployment of advanced meters throughout its service territory.[7] Entergy Arkansas will keep customers informed throughout all phases of the deployment period to expand customer engagement and reinforce understanding of the benefits offered by advanced meters. After most meters are installed, Entergy Arkansas intends to activate a web portal to allow customers to use energy management tools that leverage advanced meter data.[8] Entergy Arkansas is scheduled to complete meter deployment by the end of 2021.[9]

- **Hawaii**. On March 25, 2019, the Hawaii Public Utilities Commission (Hawaii PUC) issued an order approving Hawaiian Electric Company, Hawaii Electric Light Company, and Maui Electric Company's (collectively, HECO Companies) proposal to move forward with Phase 1 of their Grid Modernization Strategy. HECO Companies plan to deploy approximately 175,000 advanced meters, as well as a meter data management system and an upgraded communications network at a cost of $86.3 million. The Hawaii PUC authorized HECO Companies to recover Phase 1 costs between rate cases through an existing adjustment mechanism.[10]

---

[7] *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 (Arkansas PSC Dec. 7, 2018), http://www.apscservices.info/pdf/16/16-060-U_114_1.pdf.

[8] *Joint Motion Exhibit 1*, Entergy Arkansas Customer Education Plan, Docket No. 16-060-U (Arkansas PSC Sep. 28, 2018) at 18, 22, http://www.apscservices.info/pdf/16/16-060-U_110_1.pdf.

[9] *Joint Motion Exhibit 1*, Entergy Arkansas Customer Education Plan, Docket No. 16-060-U (Arkansas PSC Sep. 28, 2018) at 6, 17–19, http://www.apscservices.info/pdf/16/16-060-U_110_1.pdf.

[10] The Hawaii PUC established the Major Project Interim Recovery (MPIR) adjustment mechanism to allow utilities to recover costs between general rate cases, which occur on a three-year cycle. Eligible projects include infrastructure to improve renewable energy grid integration, projects that encourage customer load shifting and/or energy conservation, and grid modernization projects. The Hawaii PUC established the MPIR as part of a larger effort to provide utilities with incentives to make investments that are in the public interest. *See Order Establishing Performance Incentive Measures and Addressing Outstanding Schedule B Issues, Attachment A*, Docket No. 2013-0141 (Hawaii PUC Apr. 27, 2017), https://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A17D28A92300B01032.

The Hawaii PUC noted that in order for ratepayers to capture the full benefits of advanced meters, HECO Companies would need to improve customer data access and develop updated dynamic rates for all residential and commercial customers. As a condition of approved cost recovery, the Hawaii PUC required HECO Companies to file a Data Access and Privacy Policy and an Advanced Rate Design Strategy within six months of the date of the order.[11]

- **Indiana**. On May 14, 2019, the Indiana Michigan Power Company (Indiana Michigan Power) filed a petition with the Indiana Utility Regulatory Commission (IURC) to increase its retail rates and charges in order to, among other proposals, deploy advanced meters throughout its Indiana service territory to about 468,000 retail customers.[12] Indiana Michigan Power proposes to start its deployment of advanced meters in 2020, with completion scheduled by the end of 2022.[13] In conjunction with the advanced meter deployment proposal, Indiana Michigan Power proposes to give customers access to better information to make informed decisions about their energy consumption, through an engagement platform that includes billing history, energy usage information on a comparative and disaggregated basis, and customized energy efficiency tips.[14]

- **Kansas**. On July 24, 2018, the Kansas Corporation Commission (KCC) opened a general investigation into advanced meter opt-out programs, following complaints against Westar Energy and Kansas City Power & Light Company (KCP&L).[15] The KCC directed its staff to examine the types of meters that may be used in an opt-out program and to evaluate the costs associated with the installation and operation of various metering and communications alternatives. On March 14, 2019, the KCC closed the general investigation and concluded that utilities should not be required to offer an opt-out program for advanced meters.

---

[11] *Decision and Order No. 36230*, Docket No. 2018-0141 (Hawaii PUC Mar. 25, 2019), https://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A19C25B50035J00133.

[12] *Petition for Indiana Michigan Power Company, an Indiana Corporation, for Authority to Increase its Rates and Charges for Electric Utility Service through a Phase-In Rate Adjustment*, Docket No. 45235 (IURC May 14, 2019), https://iurc.portal.in.gov/_entity/sharepointdocumentlocation/34fe2120-2698-e911-8150-1458d04eaba0/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=45235_ord_20190626103522218.pdf.

[13] *Isaacson Testimony*, Docket No. 45235 (IURC May 14, 2019) at 28, https://iurc.portal.in.gov/_entity/sharepointdocumentlocation/e3f7a280-8a76-e911-8153-1458d04e2938/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=45235_IndMich_Testimony%20Direct%20Isaacson_051419.pdf.

[14] *Lucas Testimony*, Docket No. 45235 (IURC May 14, 2019) at 14, https://iurc.portal.in.gov/_entity/sharepointdocumentlocation/fbddff61-8b76-e911-8153-1458d04e2938/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=45235_IndMich_Testimony%20Direct%20Lucas_051419.pdf.

[15] *In the Matter of a General Investigation to Fully Investigate the Parameters and Intricacies of a Customer Opt-Out Program for Advanced Metering Infrastructure Digital Electric Meters*, Order Opening General Investigation, Docket No. 19-GIME-012-GIE (KCC Jul. 24, 2018), http://estar.kcc.ks.gov/estar/portal/kscc/page/docket-docs/PSC/DocketDetails.aspx?DocketId=cc56088d-20dd-4e45-9b3d-8a9559694dad.

Contrary to the claims of complainants, the KCC found no evidence that advanced meters posed any significant risk to the health, safety, or privacy of electricity customers, and they determined that requiring an opt-out program would create an unnecessary and costly administrative burden on utility operations.[16]

- **Minnesota**. On November 1, 2018, Xcel Energy filed its first-ever Integrated Distribution Plan[17] in compliance with an August 30, 2018 Order from the Minnesota Public Utilities Commission (Minnesota PUC).[18] In its Integrated Distribution Plan, Xcel Energy noted that it was preparing to propose several major distribution system investments, including full advanced meter deployment in its Minnesota service territory. Xcel Energy explained that it would refine its cost and benefit estimates and seek certification for these investments from the Minnesota PUC in a future filing. For illustrative purposes, Xcel Energy estimated that its capital costs for full advanced meter deployment and the associated field area network would be between $450 and $600 million.[19]

  In May 2018, the Minnesota PUC approved a pilot program Xcel Energy proposed to test a residential time of use (TOU) rate with customers in Minneapolis and Eden Prairie. To support this pilot program, Xcel Energy plans to deploy approximately 17,500 advanced meters in 2019 to collect baseline information before the program is launched in 2020.[20]

- **Missouri**. On June 1, 2018, the governor of Missouri signed SB 564 into law requiring each electric utility in the state to file a specific capital investment plan in furtherance of replacing,

[16] *In the Matter of a General Investigation to Fully Investigate the Parameters and Intricacies of a Customer Opt-Out Program for Advanced Metering Infrastructure Digital Electric Meters*, Order Closing General Investigation, Docket No. 19-GIME-012-GIE (KCC Jul. 24, 2018) at 14, http://estar.kcc.ks.gov/estar/ViewFile.aspx/20190314110431.pdf?Id=51ea238f-9446-47f3-8c27-b8f2e60a6075.

[17] Xcel Energy, *Integrated Distribution Plan (2018–2028): Advancing The Grid At The Speed Of Value*, Docket No. E002/CI-18-251 (Minnesota PUC Nov. 1, 2018), https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={E098D466-0000-C319-8EF6-08D47888D999}&documentTitle=201811-147534-01.

[18] *In the Matter of Distribution System Planning for Xcel Energy, Order Approving Integrated Distribution Planning Filing Requirements For Xcel Energy*, Docket No. E-002/CI-18-251 (Minnesota PUC Aug. 30, 2018), https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7BF05A8C65-0000-CA19-880C-C130791904B2%7D&documentTitle=20188-146119-01.

[19] Xcel Energy, Integrated Distribution Plan (2018–2028): Advancing The Grid At The Speed Of Value, Docket No. E002/CI-18-251 (Minnesota PUC Nov. 1, 2018) at 15.

[20] *Id.* at 118.

modernizing, and securing its infrastructure.[21] The law caps advanced meter investment to no more than six percent of annual capital expenditures during the first five years of a utility's deferral of depreciation expenses and returns.[22] To comply with the law, in February 2019, Ameren Missouri filed its five-year capital investment plan with the Missouri Public Service Commission (Missouri PSC).[23] The proposal is Ameren Missouri's largest infrastructure upgrade in company history, with approximately $1 billion in electric investments planned for 2019, including deployment of advanced meters across its service territory.[24] The Missouri PSC has yet to rule on the proposal.

- **Montana**. On April 18, 2019, the governor of Montana signed HB 267 into law, advancing the potential deployment of advanced meters in the state.[25] The legislation establishes data disclosure requirements and requires a 60-day notice before the installation of advanced meters at a customer's address. The law also requires the Montana Public Service Commission to make a determination on whether to provide customers with an opt-out for advanced meters by July 1, 2020.

- **New Jersey**. On October 11, 2018, Public Service Electric & Gas Company (PSE&G) proposed a "Clean Energy Future" program to the New Jersey Board of Public Utilities (NJ BPU) that includes approximately $4 billion in grid modernization investments.[26] PSE&G's proposal contains an "Energy Cloud" program which would deploy advanced meters to all 2.2 million electric customers in its service territory and upgrade communications and back-

---

[21] State of Missouri, *An Act to Repeal Sections 386.266, 386.390, and 393.170, RSMo, and to Enact in Lieu Thereof Twelve New Sections Relating to Public Utilities, with an Emergency Clause for a Certain Section*. SB 564, signed 6/1/2018, https://www.senate.mo.gov/18info/BTS_Web/Bill.aspx?SessionType=R&BillID=69471981.

[22] *Id.*

[23] *In The Matter Of The Compliance Of Union Electric Company D/B/A Ameren Missouri, With Certain Requirements Related To SB 564 And Related Matters*, Docket No. EO-2019-0044 (Missouri PSC Feb. 14, 2019), https://www.efis.psc.mo.gov/mpsc/commoncomponents/view_itemno_details.asp?caseno=EO-2019-0044&attach_id=2019011704.

[24] Ameren Missouri, "Ameren Missouri releases plan to transform state's energy grid to benefit customers and communities," (Feb. 15, 2019), http://ameren.mediaroom.com/2019-02-15-Ameren-Missouri-releases-plan-to-transform-states-energy-grid-to-benefit-customers-and-communities-1. *See also* Ameren, *Ameren Missouri's Smart Energy Plan*, https://www.ameren.com/-/media/missouri-site/files/smartenergyplan/report-on-ameren-missouris-smart-energy-plan.pdf?la=en-us-mo&hash=B9197A31304A0305D1F43DF8F5731DC78BF3D14A.

[25] State of Montana, *An Act Establishing Utility Requirements For The Use Of Advanced Metering Devices; Requiring A Utility To Notify A Customer Prior To Installation Of Advanced Metering Devices; Providing That Data Collected Through Use Of Metering Devices Is Generally Confidential; Providing Exceptions; Requiring The Public Service Commission To Determine Whether Implementation Of A Customer Opt-Out Program Is Required; Granting The Commission Rulemaking Authority; And Providing An Immediate Effective Date*, HB 0267, https://leg.mt.gov/bills/2019/billpdf/HB0267.pdf.

[26] PSEG, "Clean Energy Future," https://www.psegpoweringprogress.com/clean-energy-future/.

office systems to manage advanced meter data, expand customer choice and engagement, and reduce the duration of outages. The program would cost approximately $794 million, and PSE&G would deploy the advanced meters and the associated communications network between 2019 and 2024.[27] The NJ BPU had previously issued a moratorium on pre-approval of any additional advanced meter deployment, but on June 10, 2019, the NJ BPU issued the Draft 2019 New Jersey Energy Master Plan and acknowledged that statewide deployment of advanced meters will be essential in order for New Jersey to achieve its clean energy goals.[28]

- **Virginia**. As mentioned in last year's report, on July 24, 2018, Dominion Energy (Dominion) filed Phase I of its Grid Transformation Plan with the State Corporation Commission (SCC) for the Commonwealth of Virginia. Dominion requested approval for $816 million in capital costs for Phase I and included a proposal to deploy 1.4 million advanced meters in their service territory between 2019 and 2021.[29]

  On January 17, 2019, the SCC rejected the Phase I plan, including the proposed advanced meter deployment (other than $154.5 million for cyber and physical security upgrades). Although the SCC recognized the potential benefits of advanced meters, it determined that Dominion had failed to develop a comprehensive plan that would enable customers to realize savings through reduced energy usage. The SCC issued the finding without prejudice and explained that if Dominion chose to re-file a proposal for full advanced meter deployment, it should develop a comprehensive plan that includes detailed cost-estimates for advanced meter spending; proposals for time-varying rates; potential opt-out provisions and associated fees; discussion of how advanced meters can promote demand response and

---

[27] *In The Matter Of The Petition Of Public Service Electric And Gas Company For Approval Of Its Clean Energy Future-Energy Cloud ("CEF-EC") Program On A Regulated Basis*, Docket No. EO18101115 (NJ BPU Oct. 11, 2018) at 6–8, https://nj.pseg.com/aboutpseg/regulatorypage/-/media/F6F90D473FB34583991F951B9A4B8487.ashx.

[28] In August 2017, the NJ BPU issued an order authorizing Rockland Electric Company to implement an advanced meter program, but also issued a moratorium on pre-approval of any further advanced meter deployment in the state until it could determine whether "advanced metering technology is a prudent investment." However, after two major storms in March 2018 caused widespread outages, the NJ BPU directed each state electric utility to develop a plan and cost benefit analysis for advanced meter deployment. See *In the Matter of the Petition of Rockland Electric Company for Approval of An Advanced Metering Program; and for Other Relief*, Docket No. ER16060524 (NJ BPU Aug. 23, 2017) at 24, https://www.bpu.state.nj.us/bpu/pdf/boardorders/2017/20170823/8-23-17-2F.pdf; *In The Matter of the Board's Review Of Major Storm Events Of March 2018*, Order Accepting Staff's Report Requiring Utilities To Implement Recommendations, Docket No. EO18030255 (NJ BPU Jul. 25, 2018) at 10, https://nj.gov/bpu/pdf/boardorders/2018/20180725/7-25-18-6A.pdf; New Jersey Board of Public Utilities, *Draft 2019 New Jersey Energy Master Plan: Policy Vision to 2050*, at 78, https://nj.gov/emp/pdf/Draft%202019%20EMP%20Final.pdf.

[29] *Petition of Virginia Electric and Power Company, For approval of a plan for electric distribution grid transformation projects pursuant to § 56-585.1 (A)(6) of the Code of Virginia*, Case No. PUR-2018-00100, (Virginia SCC Jul. 24, 2018), http://www.scc.virginia.gov/docketsearch/DOCS/3mq601!.PDF.

energy efficiency; and customer education plans.[30] Dominion filed a revised proposal on September 30, 2019, requesting approval for $510 million in grid modernization capital investments that would include full advanced meter deployment across the utility's Virginia service territory.[31]

Collaborative industry-government efforts

In response to requests in 2011 from the White House, the Department of Energy (DOE), and the National Institute of Science and Technology (NIST), utilities formed the Green Button Alliance to help develop and adopt a "Green Button" to provide customers with detailed energy usage information. On September 5, 2018, the Green Button Alliance announced the launch of a new Green Button Connect My Data certification program designed to ensure utilities using the Green Button Standard provide customers and third-party vendors with secure and standardized energy consumption and billing information.[32] In other words, the Green Button Alliance certification process ensures compliance with its standards-based data access and data sharing protocols. In January 2019, UtilityAPI's EE/DER Engagement Platform became the first U.S.-based data exchange tested and certified as compliant with the new Green Button Alliance certification program.[33]

On April 8, 2019, the North American Energy Standards Board (NAESB) ratified the latest revision of the NAESB Energy Services Provider Interface Retail Energy Quadrant Book 21 (REQ.21) standard, commonly known as the Green Button Standard. The updates include revised data structures and definitions as well as enhanced security requirements to protect customers' personally identifiable information.[34]

---

[30] *Petition of Virginia Electric and Power Company, For approval of a plan for electric distribution grid transformation projects pursuant to § 56-585.1 (A)(6) of the Code of Virginia*, Final Order, Case No. PUR-2018-00100, (Virginia SCC Jan. 17, 2019), http://www.scc.virginia.gov/docketsearch/DOCS/4dv801!.PDF.

[31] *Petition of Virginia Electric and Power Company, For approval of a plan for electric distribution grid transformation projects pursuant to § 56-585.1 A 6 of the Code of Virginia, and for approval of an addition to the terms and conditions applicable to electric service*, Case No. PUR-2019-0154, (Virginia SCC Sept. 30, 2019), http://www.scc.virginia.gov/docketsearch/DOCS/4j4b01!.PDF.

[32] Green Button Alliance, "Green Button Alliance Launches Green Button Connect My Data (CMD) Certification Program for Electricity, Natural Gas, and Water Utilities," (Sep. 5, 2018), https://www.greenbuttonalliance.org/green-button-alliance-launches-green-button-connect-my-data--cmd--certification-program-for-electricity--natural-gas--and-water-utilities.

[33] Green Button Alliance, "Green Button Alliance Member UtilityAPI's New Utility Data Exchange Platform Certified as Green Button Connect My Data (CMD) Compliant" (Jan. 29, 2019), https://www.greenbuttonalliance.org/index.php?option=com_content&view=article&id=111:green-button-alliance-member-utilityapi-s-new-utility-data-exchange-platform-certified-as-green-button-connect-my-data--cmd--compliant&catid=23:green-button-news&Itemid=114.

[34] North American Energy Standards Board, *Green Button Activities Update* (Apr. 8, 2019), https://www.naesb.org/pdf4/update061919w2.docx.

III. 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.[35]

Retail demand response programs

Table 3-1 presents data collected by EIA on 2016 and 2017 potential peak demand savings from retail demand response programs within each of the eight NERC regional entities, as well as Alaska and Hawaii.[36] The term "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."[37] Nationwide, total potential peak demand savings from retail demand response programs decreased by 4,417 MW, or 12 percent, between 2016 and 2017, from 35,924 MW to 31,508 MW.

[35] 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 2016 and 2017, as well as RTO/ISO wholesale data for 2017 and 2018.

[36] 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.

[37] *See* EIA, Form EIA-861 Instructions, Schedule 6, Part B. Potential peak demand savings differ from actual peak demand savings, which, according to EIA, totaled 12,248 MW in 2017.

Table 3-1: Potential Peak Demand Savings (MW) from Retail Demand Response Programs, by Region (2016 & 2017)

Region	Annual Potential Peak Demand Savings (MW)		Year-on-Year Change	
	2016	2017	MW	Percent
Alaska	27.0	27.0	0.0	0.0%
FRCC	3,259.4	3,112.4	-147.0	-4.5%
Hawaii	33.5	32.6	-0.9	-2.7%
MRO	5,231.3	5,364.5	133.2	2.5%
NPCC	1,120.2	821.4	-298.8	-26.7%
ReliabilityFirst	5,505.1	6,171.0	665.9	12.1%
SERC	8,265.6	8,787.9	522.3	6.3%
SPP RE	5,004.4	1,700.4	-3,304.0	-66.0%
Texas RE	773.3	823.8	50.5	6.5%
WECC	6,625.3	4,553.7	-2,071.6	-31.3%
Unspecified	79.0	112.8	33.8	42.8%
Total	**35,924.1**	**31,507.5**	**-4,416.6**	**-12.3%**

Sources: EIA, EIA-861 Demand_Response_2016, Demand_Response_2017, Utility_Data_2016, and Utility_Data_2017 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.

The decrease in potential peak demand savings from 2016 to 2017 at the retail level was largely concentrated in the SPP RE and WECC regions. SPP RE accounted for the largest decrease from 2016 to 2017, roughly 3,300 MW, due to lower reported savings by Oklahoma Gas and Electric Company. WECC also reported lower potential peak demand savings in 2017, due primarily to large decreases reported by Salt River Project and Southern California Edison. The decrease in potential peak demand savings at the retail level in WECC likely reflects a shift toward greater demand response participation in CAISO's wholesale market, as discussed in the next section. While potential peak demand savings decreased nationwide from 2016 to 2017, multiple regions reported an increase in savings.

Table 3-1 and Figure 3-1 show that potential peak demand savings increased in SERC by approximately 522 MW, primarily attributable to Tennessee Valley Authority's reported increase of 638 MW. Potential peak demand savings in ReliabilityFirst increased by over 665 MW, with the greatest increases reported by Indiana Michigan Power Company (288 MW), Metropolitan Edison Company (120 MW), and PECO Energy Company (118 MW).

Figure 3-1: Potential Peak Demand Savings (MW) from Retail Demand Response Programs, by Region (2013–2017)

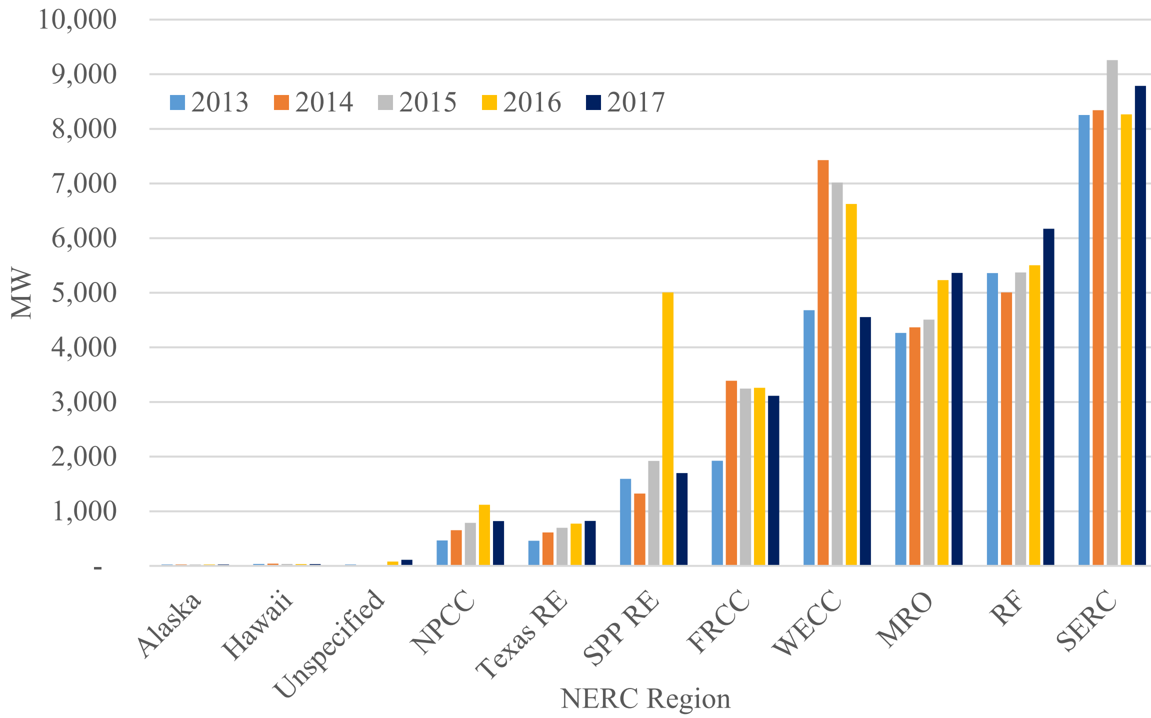


Table 3-2 shows that the amount of potential peak demand savings from retail demand response differs by customer class in 2017. Compared to 2016, industrial customers in 2017 reported an increase of 1,173 MW to 15,512 MW. In 2017, industrial customers contributed approximately 49 percent of total reported potential peak demand savings from retail demand response programs. From 2016 to 2017, commercial sector programs saw a decrease in potential peak demand savings from approximately 11,000 MW in 2016 to 6,995 MWs in 2017. Commercial customer demand response programs accounted for 22 percent of total potential peak demand savings in 2017. Residential customer demand response accounted for approximately 8,996 MW, or approximately 29 percent of the total potential peak demand savings for 2017 retail demand response programs.

The relative contribution by customer class varies by region. For example, industrial demand response programs account for the largest portion of potential peak demand savings in SERC (72 percent), ReliabilityFirst (58 percent), and WECC (47 percent). Commercial programs account for the majority of potential peak demand savings in Alaska, Hawaii, NPCC, SPP RE, and Texas RE. In FRCC and MRO, residential programs account for the highest proportion of potential peak demand savings, at 48 and 40 percent, respectively.

Table 3-2: Potential Peak Demand Savings (MW) from Retail Demand Response Programs, by Region and Customer Class (2017)

Region	Customer Class				
	Residential	Commercial	Industrial	Transportation	All Classes
Alaska	5.0	13.0	9.0	0.0	27.0
FRCC	1,500.7	1,335.7	276.0	0.0	3,112.4
Hawaii	14.2	18.4	0.0	0.0	32.6
MRO	2,158.1	1,103.2	2,098.4	5.0	5,364.5
NPCC	120.1	385.1	316.3	0.0	821.4
ReliabilityFirst	1,658.2	907.7	3,605.2	0.0	6,171.0
SERC	1,617.2	805.2	6,365.5	0.0	8,787.9
SPP RE	280.9	966.6	453.0	0.0	1,700.4
Texas RE	238.1	376.0	209.8	0.0	823.8
WECC	1,351.0	1,084.3	2,118.5	0.0	4,553.7
Unspecified	52.5	0.0	60.3	0.0	112.8
All Regions	**8,996**	**6,995**	**15,512**	**5**	**31,508**

Sources: EIA, EIA-861 Demand_Response_2017 and Utility_Data_2017 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.

Wholesale demand response programs

Table 3-3 below presents demand resource participation (i.e., registration) in RTO/ISO wholesale demand response programs in 2017 and 2018.[38] In 2018, overall demand resource participation in the wholesale markets increased by approximately 2,133 MW, or almost eight percent, to a total of 29,674 MW.[39] On a regional basis, participation increased most in CAISO and MISO, while participation decreased most in ISO-NE.

[38] The RTOs/ISOs include California ISO (CAISO), Electric Reliability Council of Texas (ERCOT), ISO New England (ISO-NE), Midcontinent Independent System Operator (MISO), New York Independent System Operator (NYISO), PJM Interconnection (PJM), and Southwest Power Pool (SPP).

[39] Commission staff estimates of demand response resource participation in the wholesale markets are based on enrollment in reliability, energy, and ancillary services products administered by each RTO/ISO. Figures do not include energy efficiency. By comparison, the Smart Electric Power Alliance estimates a total of 23,430 MW of demand resources participating in RTO/ISO reliability programs in 2018. *See* SEPA, *2019 Utility Demand Response Market Snapshot*, at 29, https://sepapower.org/resource/2019-utility-demand-response-market-snapshot/.

Table 3-3: Demand Resource Participation in RTOs/ISOs (2017 & 2018)

RTO/ISO	2017		2018		Year-on-Year Change	
	Demand Resources (MW)	Percent of Peak Demand [8]	Demand Resources (MW)	Percent of Peak Demand [8]	MW	Percent
CAISO	1,293 [1]	2.6%	2,400 [9]	5.2%	1,107	85.6%
ERCOT	3,009 [2]	4.3%	3,262 [10]	4.4%	253	8.4%
ISO-NE	684 [3]	2.9%	356 [11]	1.4%	-328	-48.0%
MISO	11,682 [4]	9.7%	12,931 [12]	10.6%	1,249	10.7%
NYISO	1,353 [5]	4.6%	1,431 [13]	4.5%	78	5.8%
PJM	9,520 [6]	6.7%	9,294 [14]	6.3%	-226	-2.4%
SPP	0 [7]	0.0%	0 [7]	0.0%	0	0.0%
Total	**27,541**	**5.6%**	**29,674**	**6.0%**	**2,133**	**7.7%**

Sources:

[1] CAISO, *2017 Annual Report on Market Issues and Performance* (Jun. 2018), at 36-37. [2] Estimated based on ERCOT, *2017 Annual Report of Demand Response in the ERCOT Region* (Mar. 2018), at 2–6. [3] ISO-NE, *Demand Resource Asset Enrolled MWs*, presented at Demand Resources Working Group Meeting (Dec. 18, 2017) (data as of Jan. 1, 2018), at 2. Figure represents real-time demand resource asset enrolled MWs. [4] *2017 State of the Market Report for the MISO Electricity Market* (Jun. 2018), Table 11, at 78. [5] *2017 Annual Report on Demand Side Management Programs of the New York Independent System Operator, Inc.*, ER01-3001 (Jan. 12, 2018), Attachment I, at 6 (Table 1). [6] *PJM 2017 Demand Response Operations Markets Activity Report* (Apr. 2018), at 3–4. Figure represents "unique 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 (May 24, 2016), at 4; and SPP Response to Request for Additional Information, Docket No. ER12-1179-025 (Mar. 5, 2018), at 1–2, 4. [8] Sources for peak demand data include: CAISO *2017* and *2018 Annual Reports on Market Issues and Performance*; *ERCOT 2017 & 2018 Demand and Energy Reports*; *ISO-NE Net Energy and Peak Load Report* (Jul. 2019); *2017* and *2018 State of the Market Reports for the MISO Electricity Markets*; *NYISO Power Trends Reports 2018* and *2019*; *2017* and *2018 PJM State of the Markets Reports, Vol. 2*; *SPP 2018 State of the Market Report.* [9] CAISO, *2018 Annual Report on Market Issues and Performance* (May 2019), at 42. [10] Estimated based on ERCOT, *2018 Annual Report of Demand Response in the ERCOT Region* (Mar. 2019), at 3–6. [11] ISO-NE, *Monthly Statistics Report*, presented at Demand Resources Working Group Meeting (Dec. 27, 2018) (data as of Dec. 1, 2018), at 4. Figure represents Demand Response Asset MWs with a capacity supply obligation. [12] *2018 State of the Market Report for the MISO Electricity Market* (Jun. 2019), Table 15, at 91. [13] *2018 Annual Report on Demand Side Management Programs of the New York Independent System Operator, Inc.*, ER01-3001 (Jan. 14, 2019), Attachment I, Table 1, at 7. [14] *PJM 2018 Demand Response Operations Markets Activity Report* (Mar. 2019), at 3–4. Figure represents "unique MW." *Note:* Commission staff has not independently verified the accuracy of the sources listed. Values from source data are rounded for publication.

CAISO reported the largest percentage increase, 85.6 percent, or 1,107 MW, in demand resource participation from 2017 to 2018. In CAISO, there has been a shift away from utility-sponsored price responsive demand response programs to greater participation in CAISO's Proxy Demand Response program, through which resources can bid economically in the energy market, and in the Reliability Demand Response program. Enrollment in the Proxy Demand Response program increased by 430 MW and in the Reliability Demand Response Resource program by 677 MW. Demand resource participation in these two programs has grown steadily over the past several years, from a total of 50 MW in 2014 to 2,400 MW in 2018.

In MISO, overall demand resource enrollment increased by more than ten percent, or 1,249 MW, from 2017 to 2018. Most of the increase in MISO is a result of a 1,025 MW increase in the number of resources enrolled as Load Modifying Resources (LMRs).[40] These increases were offset slightly by a decrease of 267 MW of resources enrolled in MISO's Emergency DR program.

In ERCOT, demand resource participation increased in 2018 by over 250 MW, to 3,262 MW. Continuing a trend from previous years, the majority of this growth is due to a 237 MW increase in resources participating in the Responsive Reserve Service (RRS),[41] through which demand-side resources can provide frequency response. The remainder of the increase from 2017 to 2018 was due to slightly greater enrollment in both the Fast Responding Regulation Service (FRRS)[42] and in the Emergency Response Service (ERS) programs.[43]

Conversely, ISO-NE reported the greatest percentage change in demand resource participation, a 48 percent decrease, from 2017 to 2018. The reason for the decrease in demand resource participation in ISO-NE is unclear. However, the decrease coincides with the implementation of ISO-NE's Pay-for-Performance program, which places more stringent requirements on resources – including demand resources – participating in ISO-NE's forward capacity market. Pay-for-Performance was introduced concurrently with the full integration of demand response into ISO-NE's price-responsive demand program in June 2018, which replaced the real-time demand response program.

In addition, PJM reported an overall decrease in demand resource enrollment from 2017 to 2018. An increase of 243 MW enrolled in economic programs was offset by a decrease of 177 MW in load management programs, leading to an overall decrease in program enrollment of 226 MW. This overall decrease in demand resource registrations in PJM may be due to the continued phasing out

[40] Approximately 90 percent of demand response enrollment in MISO is in the form of LMRs that are interruptible load developed under regulated utility programs and behind-the-meter generators that clear in MISO's annual capacity auction. *See* Potomac Economics, *2018 State of the Market Report for the MISO Electricity Market* (June 2019), at 92.

[41] Load resources with an under-frequency relay may participate in the RRS to provide frequency response. Commission staff estimated participation in the RRS program based on the average offers for December 2017 and 2018; resources must be registered and qualified to offer into the market. While ERCOT reports that as much as 5,064 MW of resources were capable of participating in RRS as of the end of 2018 – a growth of 349 MW over 2017 – not all of these resources were actively participating in the market. *See* ERCOT, *2018 Annual Report of Demand Response in the ERCOT Region* (Mar. 2018), at 2–4. In June 2018, changes allowed up to 60 percent (previously 50 percent) of the total required RRS capacity to be provided by under-frequency relay Load Resources, subject to a constraint that requires at least 1,150 MW of RRS capacity to come from resources providing Primary Frequency Response.

[42] FRRS allows market participants using energy storage resources to participate as a Generation Resource when they inject energy onto the grid and as a Controllable Load Resource (CLR) when they withdraw from the grid. In 2018, there were six CLRs registered that provided an average of 35 MW in each hour.

[43] The ERS provides 10- and 30-minute load reduction services. Commission staff estimated ERS capacity by averaging the capacity procured for the six time periods in the last contract term of each program year (i.e., October to January), and summing these averages for each of the four ERS products (i.e., 10- and 30-minute types of weather-sensitive and non-weather-sensitive ERS).

of legacy demand response products as PJM completes its transition to an annual capacity performance product.

2019 demand response deployments

High demand for electricity led grid operators and utilities in several regions to issue notices for emergency demand response, critical peak pricing, and voluntary conservation. This section covers emergency demand response deployments in ERCOT, MISO, CAISO, and PJM in 2019. As of this writing, other RTO/ISO regions did not deploy emergency demand response in 2019. The report does not cover dispatch of economic demand response resources in the wholesale markets.

In mid-August 2019, Texas experienced a number of days where temperatures reached triple digits, leading to record electricity demand and calls for voluntary conservation. On August 12, ERCOT set a new all-time peak record of 74,666 MW, exceeding the previous record set in 2018.[44] On August 13 and 15, due to a combination of high demand, reduced wind production, and thermal generation outages, reserves fell below the 2,300 MW threshold, leading ERCOT to issue a Level 1 Energy Emergency Alert on both days, the first such emergencies since 2014. Energy prices reached ERCOT's $9,000 price cap in late afternoon on both days.[45] In response to tight conditions, ERCOT, among other things, issued a call for voluntary conservation[46] and deployed 30-minute ERS resources to reduce load.[47] Overall, ERS deployment helped reduce load by about 3,100 MW on August 13 and by 1,800 MW on August 15.[48] In addition, ERCOT deployed RRS – a service in which load resources may participate to provide frequency response – during this period of extreme

---

[44] RTO Insider, "ERCOT Sets New Demand Mark, Smashes '18 Record," (Aug. 13, 2019), https://rtoinsider.com/ercot-new-demand-record-141136/; S&P Global Platts Megawatt Daily, "Demand response helped ensure grid reliability in ERCOT this summer," (Oct. 9, 2019).

[45] RTO Insider, "ERCOT Survives Another Day in the Roaster," (Aug. 14, 2019), https://rtoinsider.com/ercot-survives-another-day-141229/; RTO Insider, "ERCOT calls 2nd energy emergency this week, 3rd in 5 years," (Aug. 16, 2019), https://www.utilitydive.com/news/ercot-calls-2nd-energy-emergency-this-week-3rd-in-5-years/561065/. *See also* RTO Insider, "ERCOT CEO Briefs Commission on Summer Performance," (Sep. 2, 2019), https://rtoinsider.com/texas-puc-082919-141858/.

[46] ERCOT, "High temperatures likely to result in record electricity demand today," (Aug. 13, 2019), http://ercot.com/news/releases/show/187763.

[47] During emergency conditions, MISO called on all available resources, deployed operating reserves and its 30-minute emergency response service, and requested energy imports over its ties with neighboring RTOs. *See* RTO Insider, "ERCOT Calls 2nd Energy Alert in 3 Days," https://rtoinsider.com/ercot-second-energy-alert-141299/. *See also supra* n.42.

[48] S&P Global Platts Megawatt Daily, "Demand response helped ensure grid reliability in ERCOT this summer," (Oct. 9, 2019).

heat in August, as well on multiple occasions in March, April, May, and July. Many of these deployments coincided with a decrease in system frequency due to the sudden loss of generation.[49]

Continuing a trend over the last few years of more frequently deploying demand response during emergency events and outside the summer season, MISO activated LMRs on January 30, 2019, after declaring an Energy Emergency Alert Level 2 emergency in the MISO Central and North Regions.[50] The market monitor for MISO expects that, as the region's surplus capacity decreases, demand response resources will be deployed more frequently to meet peak loads and to respond to system contingencies.[51]

In response to high temperatures and high energy demand, CAISO issued a state-wide Flex Alert[52] calling for voluntary electricity conservation during the evening of June 11, 2019.[53] In addition, some investor-owned utilities in California called critical peak pricing days[54] for their retail customers on several occasions this summer: Pacific Gas & Electric (PG&E) in mid-June and late July[55] and Southern California Edison (SCE) in mid-July.[56]

On October 2, 2019, the PJM footprint experienced its second-highest October demand on record, reaching more than 126,000 MW, prompting PJM to declare a Pre-Emergency Load Management Reduction Action.[57] As part of this action, PJM called on interruptible customers in the American Electric Power (AEP), Baltimore Gas & Electric (BGE), Dominion, and Potomac Electric Power

---

[49] ERCOT, "Operations Messages," http://www.ercot.com/services/comm/mkt_notices/opsmessages. *See also supra* n.40.

[50] Potomac Economics, *2018 State of the Market Report*, at 92–94, https://www.potomaceconomics.com/wp-content/uploads/2019/06/2018-MISO-SOM_Report_Final2.pdf. *See also supra* n.39.

[51] *Id.* at 92.

[52] Flex Alerts are voluntary calls for consumers to conserve electricity when there is a predicted shortage of energy supply. *See* CAISO, "What Is a Flex Alert," http://www.flexalert.org/what-is-flex-alert.

[53] CAISO, "Flex Alert," http://www.flexalert.org/.

[54] Critical peak pricing rates typically charge a much higher price for a few hours on critical peak days, when demand for electricity is expected to be extremely high. *See* FERC, *Assessment of Demand Response & Advanced Metering*, Appendix C (2008).

[55] PG&E, "2019 Peak Day Pricing Event Days," https://www.pge.com/en_US/small-medium-business/your-account/rates-and-rate-options/peak-day-pricing/event-day-history.page.

[56] SCE, "Event History," https://www.sce.openadr.com/dr.website/scepr-event-history.jsf.

[57] A Pre-Emergency Load Management Reduction Action provides load relief by using PJM-controllable load management programs in which customers receive compensation for agreeing to reduce their consumption during times of grid stress.

Company (PEPCO) zones to reduce load in the afternoon.[58] The action also triggered a Performance Assessment Interval under PJM's Capacity Performance program, which assesses a penalty on, or provides a payment to, resources based on a comparison of their capacity obligations during emergencies and their actual performance.[59]

[58] PJM Inside Lines, "Utilities, Generators, Demand Response Keep Grid Reliable on Challenging Day" (Oct. 2, 2019), https://insidelines.pjm.com/utilities-generators-demand-response-keep-grid-reliable-on-challenging-day/.

[59] S&P Global Platts, "Warm Mid-Atlantic US weather prompts PJM demand response, $4,000/MWh power prices" (Oct. 3, 2019).

IV. Potential for demand response as a quantifiable, reliable resource for regional planning purposes

NERC's Demand Response Availability Data System and planning for a changing resource mix

NERC, as the Commission-certified Electric Reliability Organization, develops and enforces mandatory reliability standards that provide for reliable operation of the bulk power system.[60] NERC notes that demand response "can support reliability during forecast or actual reserve shortages, reliability events, or assisting with frequency control."[61] For example, in its latest *State of Reliability* report, NERC reports that in the 2018 summer season in Texas, the use of demand response resources, along with higher than average peak availability from both wind and conventional generation, helped avoid a need for emergency operating procedures.[62] NERC uses transmission, generation, and demand response data systems to analyze past performance of the bulk power system and to identify performance trends.[63] Specifically, NERC's Demand Response Availability Data System (DADS), measures demand response performance, in part, to gauge the extent to which demand response resources reliably and consistently perform to ensure reliable planning and operations.

In addition, NERC notes that ongoing changes in the North American power system's resource mix – e.g., the growth of, among other things, natural-gas-fired generation, renewable forms of asynchronous generation, electric storage, and demand response – may necessitate changes to bulk power system planning, operational practices and procedures, reliability standards, and market design.[64] For instance, NERC recommends that, in collaboration with industry, it should (1) continue to expand the use of probabilistic approaches to resource adequacy to reflect the variability and reliability characteristics of these types of resources; and (2) develop guidelines and good

---

[60] 16 U.S.C. §§ 824o(a)(2), 824o(c) (2005).

[61] *Id*. at 6.

[62] NERC, *State of Reliability* (Jun. 2019) at viii, https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2019.pdf.

[63] Specifically, these are NERC's Transmission Availability Data System (TADS), the Generation Availability Data System (GADS), and the Demand Availability Data System (DADS).

[64] NERC, *State of Reliability* (Jun. 2019) at 50, https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2019.pdf.

industry practice for establishing and maintaining accurate system models, including generation resources, load resources, and controllable devices that provide essential reliability services.[65]

[65] *Id.*, Appendix B (Compilation of Recommendations).

V. Existing retail demand response and time-based rate programs

Based on EIA survey data and program definitions, this chapter provides information on retail (incentive-based) demand response[66] and time-based rate programs[67] in 2016 and 2017, and summarizes recent actions taken at the federal, regional, and state levels, and by industry, related to demand response. Since 2013, nationwide enrollment in time-based rate programs has increased by 2.5 million (or 42 percent), while enrollment in incentive-based demand response programs has increased by only 250,000 (or 3 percent). This may signal that utilities in certain regions are focusing on increasing enrollment in time-based rate programs in order to leverage their advanced meter investments.

Enrollment in retail demand response and time-based rate programs

As shown in Table 5-1 and Figure 5-1 below, in 2017 the number of retail customers enrolled in (incentive-based) demand response programs nationwide decreased by four percent, or almost 400,000 customers, to approximately 9.4 million customers. However, since 2013, nationwide enrollment in incentive-based demand response programs has grown by 250,000, or 3 percent.

On a regional basis, Alaska, SPP RE, and Texas RE, all reported an increase in the number of customers enrolled in retail demand response programs. The largest percentage increase in such customer enrollment occurred in the SPP RE region, where enrollments increased by about 71 percent from 2016 to 2017 to approximately 312,000 customers. According to EIA data, this increase was primarily due to higher reported enrollment in the program run by Oklahoma Gas and Electric Company.

In contrast, enrollment fell by 13 percent, or almost 10,000 customers, in NPCC due to reported decreases in enrollment in programs run by Consolidated Edison and Long Island Power Authority in New York. Enrollment in WECC fell by almost 12 percent, or approximately 370,000 customers, primarily due to a decrease of over 380,000 customers in reported enrollment in Southern California Edison's residential program. Enrollment in ReliabilityFirst decreased by approximately 122,000, or five percent, primarily due to a decrease in enrollment of approximately 162,000 customers reported by PEPCO. By contrast, Consumers Energy Co. (Consumers Energy) and Pennsylvania Power Co.

---

[66] Demand response programs include direct load control, interruptible, demand bidding/buyback, emergency demand response, capacity market, and ancillary service market programs. Previously, EIA referred to these programs as "incentive-based" demand response programs. See EIA, Form EIA-861 Instructions, Schedule 6-Part B, https://www.eia.gov/survey/form/eia_861/instructions.pdf; and FERC, *A National Assessment of Demand Response Potential* (2009), http://www.ferc.gov/legal/staff-reports/06-09-demand-response.pdf.

[67] Time-based rate programs include real-time pricing, critical peak pricing, critical peak rebate, variable peak pricing, and time-of-use rates administered through a tariff. EIA now refers to these programs as "dynamic pricing" programs. See EIA, Form EIA-861 Instructions, Schedule 6-Part C, https://www.eia.gov/survey/form/eia_861/instructions.pdf.

(Penn Power) reported increases in enrollment of 46,100 and 30,000 customers, respectively. Enrollment also fell in FRCC, Hawaii, MRO, ReliabilityFirst, SERC, and for entities that did not specify a NERC region.

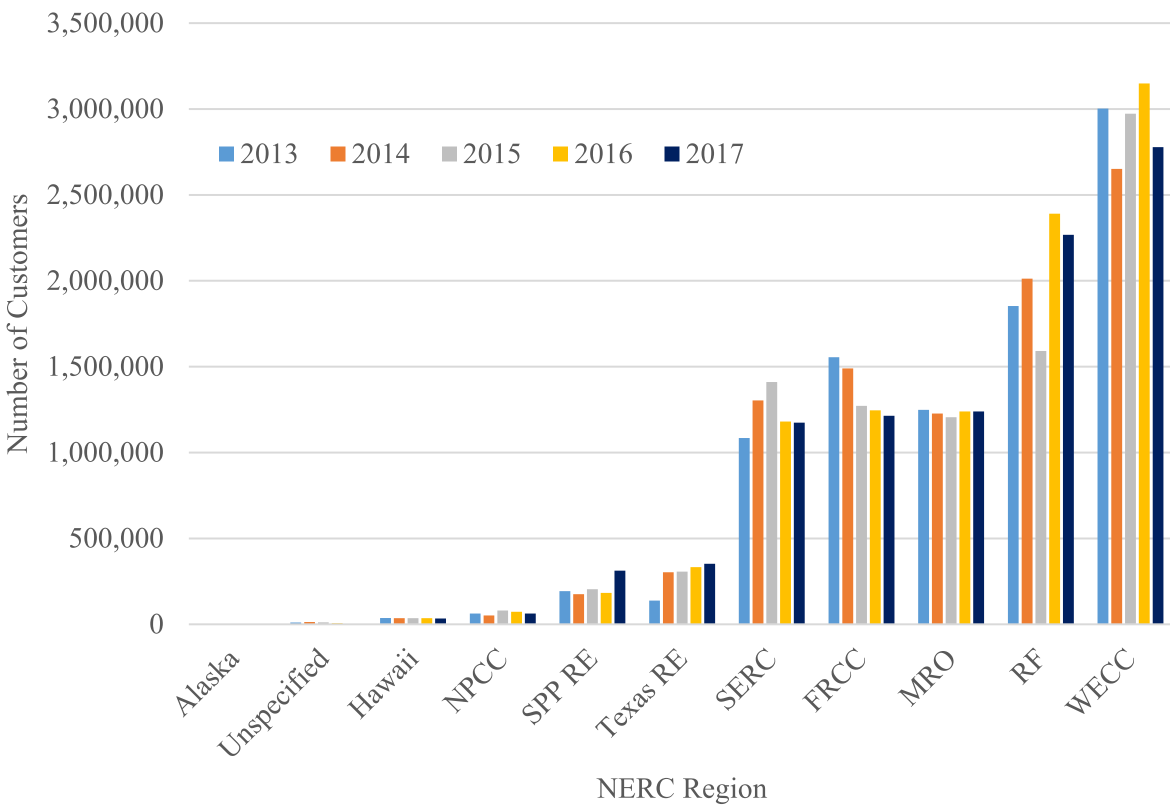
Table 5-1: Customer Enrollment in Retail Demand Response Programs, by Region (2016 & 2017)

Region	Enrollment in Retail Demand Response Programs		Year-on-Year Change	
	2016	2017	Customers	Percent
Alaska	2,403	2,414	11	0.5%
FRCC	1,245,403	1,214,003	-31,400	-2.5%
Hawaii	36,160	34,055	-2,105	-5.8%
MRO	1,239,580	1,239,050	-530	0%
NPCC	72,969	63,155	-9,814	-13.4%
ReliabilityFirst	2,390,143	2,267,920	-122,223	-5.1%
SERC	1,180,884	1,173,951	-6,933	-0.6%
SPP RE	182,576	312,461	129,885	71.1%
Texas RE	333,236	352,072	18,836	5.7%
WECC	3,148,899	2,778,440	-370,459	-11.8%
Unspecified	7,102	3,417	-3,685	-51.9%
Total	**9,839,355**	**9,440,938**	**-398,417**	**-4.0%**

Sources: EIA, EIA-861 Demand_Response_2016, Utility_Data_2016, Demand_Response_2017, and Utility_Data_2017 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.

Figure 5-1: Customer Enrollment in Retail Demand Response Programs, by Region (2013–2017)



As Table 5-2 below indicates, there were almost 8.5 million customers enrolled in retail time-based rate programs in the United States in 2017, an increase of over 547,000 customers, or 6.9 percent, from 2016. Since 2013, enrollment in time-based rate programs has increased by 2.5 million, or 42 percent.

The bulk of the increase from 2016 to 2017 in absolute terms occurred in the ReliabilityFirst and WECC regions, with approximately 164,000 and 348,000 new customer enrollments, respectively. The increase in enrollment in ReliabilityFirst is primarily due to significant enrollment increases in existing residential programs run by Commonwealth Edison, with other large increases seen in programs run by BGE, Consumers Energy, Delmarva Power, and PEPCO. Hawaii reported the highest percentage increase from 2016 to 2017, primarily attributable to over 1,500 new customers enrolled in Hawaiian Electric Company's residential programs. Overall, the increase in customer enrollment in time-based programs more than offset the decrease in retail incentive-based demand response program enrollment, potentially signaling a shift toward time-based rate programs. In WECC, for instance, Arizona Public Service reported a decrease of approximately 3,400 customers in incentive-based programs and an increase of approximately 25,000 customers in time-based demand response programs from 2016 to 2017.

Table 5-2: Customer Enrollment in Retail Time-based Rate Programs, by Region (2016 & 2017)

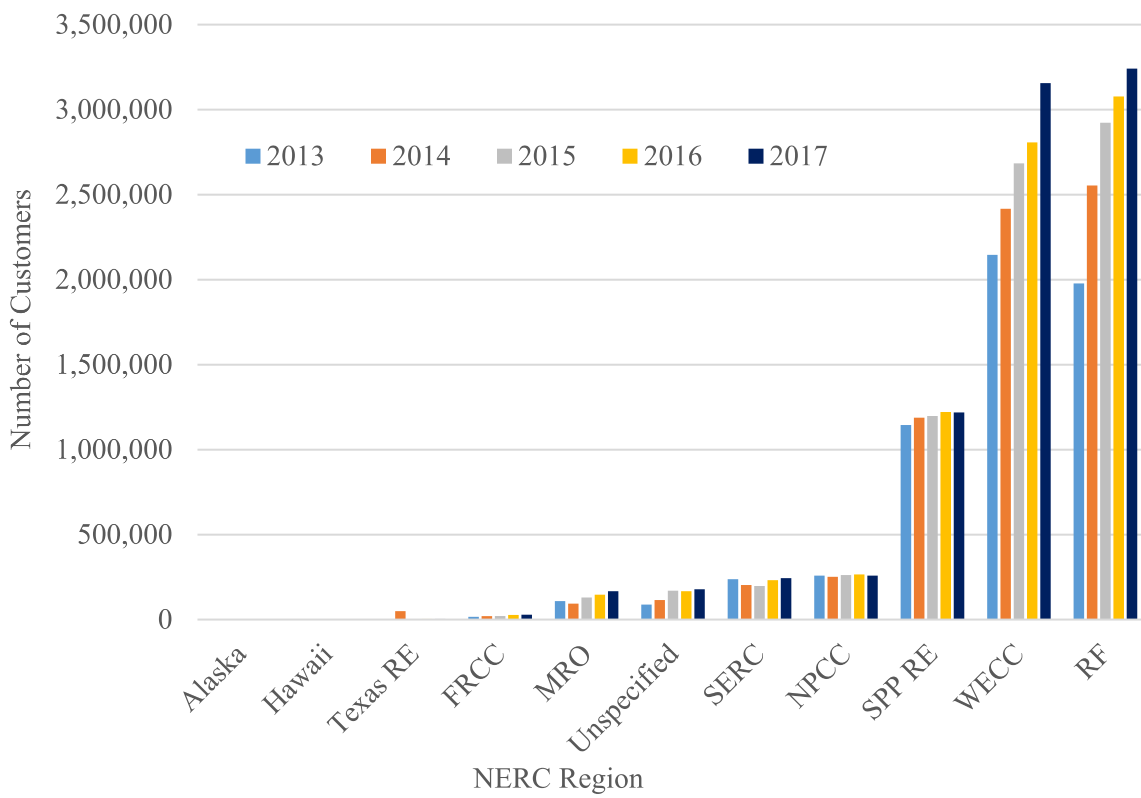
Region	Enrollment in Retail Time-based Rate Programs		Year-on-Year Change	
	2016	2017	Customers	Percent
Alaska	55	45	-10	-18.2%
FRCC	27,578	28,720	1,142	4.1%
Hawaii	568	2,665	2,097	369.2%
MRO	146,396	166,283	19,887	13.6%
NPCC	265,619	258,669	-6,950	-2.6%
ReliabilityFirst	3,077,442	3,241,696	164,254	5.3%
SERC	230,997	243,222	12,225	5.3%
SPP RE	1,222,479	1,218,448	-4,031	-0.3%
Texas RE	4,720	4,404	-316	-6.7%
WECC	2,807,596	3,155,860	348,264	12.4%
Unspecified	166,777	177,708	10,931	6.6%
Total	**7,950,227**	**8,497,720**	**547,493**	**6.9%**

Sources: EIA, EIA-861 Dynamic_Pricing_2016 and Dynamic_Pricing_2017 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.

Figure 5-2 below shows annual customer enrollment in retail time-based rate programs from 2013 to 2017. ReliabilityFirst and WECC both reported an annual increase in customers enrolled in retail time-based rate programs, continuing a trend since 2013 to 2014. Both regions report over three million customers enrolled in retail time-based rate programs, and account for approximately 75 percent of all customers enrolled in retail time-based rate programs nationwide. FRCC, Hawaii, MRO, and SERC all reported an increase in the number of customers enrolled for at least the second year in a row. Despite minor decreases from 2016 to 2017, SPP RE and NPCC still account for the third and fourth highest number of customers enrolled, respectively.

Figure 5-2: Customer Enrollment in Retail Time-based Rate Programs, by Region (2013–2017)



FERC demand response orders and activities

PJM Seasonal Demand Resource Registration Aggregation (Docket No. ER19-244-000)

On December 31, 2018, the Commission approved PJM's proposed tariff revisions to, among other things, change how it determines the capacity values associated with a Demand Resource and the underlying demand resource registrations.[68] Under the accepted revisions, PJM will no longer calculate an annual nominated capacity value for each demand resource registration, instead calculating only summer-period and winter-period nominated capacity values for each registration. PJM will use the summer- and winter-period capacity values for all registrations to calculate the annual load reduction capability of a Demand Resource that participates in PJM's capacity market. The Commission found that PJM's proposal, by modifying the structure of Demand Resource registration to reflect seasonal capabilities, helps ensure accurate characterization of the curtailment capabilities of end-use customers.

[68] *PJM Interconnection, L.L.C.*, 165 FERC ¶ 61,281 (2018).

MISO Tariff Revisions related to Load Modifying Resources (Docket No. ER19-650-000)

On February 19, 2019, the Commission approved MISO's proposed tariff revisions to allow MISO to more effectively access the capabilities of LMRs during system emergencies.[69] Under MISO's then-existing tariff, LMRs that clear the Planning Resource Auction were required to be available only during the summer season to respond to certain severe emergency events, could be deployed no more than five times per planning year, and were required to be given up to 12 hours of notice before being deployed. MISO noted in its filing that recent Maximum Generation Emergency events have frequently occurred outside the summer months, and that this fact did not align well with the current obligations on LMRs. Under the accepted revisions, each LMR must: (1) offer its capability based on its actual availability in all seasons, including for the entire summer season; and (2) deploy based on the shortest notification requirement that it can consistently meet, but no more than 12 hours. In addition, MISO may issue scheduling instructions to LMRs ahead of anticipated emergency conditions, in order to mitigate the risk that LMRs with longer notification times cannot be deployed when needed.

PJM Price Responsive Demand (Docket No. ER19-1012-000, -001)

On June 27, 2019, the Commission rejected as unjust and unreasonable a filing in which PJM proposed to update the rules for Price Responsive Demand (PRD)[70] to conform to the rules for supply-side Capacity Performance Resources.[71] Specifically, PJM proposed to: (1) change the method for determining a load serving entity's (LSE) load reduction value and associated capacity bill credit from a calculation based on PRD resources' load reduction during PJM's summer peak to a calculation based on the lesser of the resources' summer and winter load reductions; (2) assess performance penalties and award performance payments to PRD resources in accordance with rules for Capacity Performance Resources; and (3) revise the credit rate for PRD resources to conform with the credit requirements for Capacity Performance Resources. The Commission found that PJM had not shown that it is just and reasonable to calculate the load reduction value and associated capacity bill credit based on the lesser of summer and winter load reductions, because such as a method conflicts with the manner in which PJM calculates an LSE's capacity obligation.

---

[69] *Midcontinent Independent System Operator, Inc.*, 166 FERC ¶ 61,116 (2019). See also supra n. 39.

[70] PJM's PRD program provides load serving entities an opportunity to designate a portion of their load as price-responsive – with customers subject to certain eligibility requirements, such as being on a dynamic rate and having an advanced meter – in order to reduce the load serving entity's bills for energy and capacity.

[71] *PJM Interconnection, L.L.C.*, 167 FERC ¶ 61,268 (2019).

AEE Petition for Declaratory Order regarding Measurement and Verification Standards for Energy Efficiency Resources (EL19-43-000)

On April 26, 2019, the Commission dismissed as premature Advanced Energy Economy's and Sustainable FERC's petition related to how ISO-NE measures demand reduction values of energy efficiency resources for purposes of participating in its Forward Capacity Market.[72] Specifically, the petitioners requested two determinations: (1) ISO-NE may not retroactively revise approved Forward Capacity Auction 13 Qualification Packages to introduce new Measurement and Verification (M&V) standards; and (2) ISO-NE may not change the requirements for determining the capacity value of energy efficiency resources going forward, including imposing any requirement to convert from adjusted gross savings to net savings, without approval from the Commission. The Commission found that the harm alleged in the petition is speculative in light of ISO-NE's statement that it had not made any proposal, nor did it have any plans, to change its M&V standards. In addition, the Commission found that because ISO-NE had not proposed a change to its M&V standards, there was no concrete proposal for the Commission to evaluate to determine whether a tariff filing is required, and thus no controversy or uncertainty necessitating a declaratory finding.

Other federal demand response activities

U.S. Department of Defense

The U.S. Department of Defense's (DoD) Defense Logistics Agency Energy (DLA Energy) provides the DoD and other federal government agencies with comprehensive energy solutions,[73] including administering incentive-based demand response programs. In fiscal year 2018, DLA Energy operated 30 demand response installations in eight states and the District of Columbia – all of which are within organized wholesale markets – and had 73 MW of demand response enrolled in its programs.[74] Enrollment has declined over time, after reaching a high of approximately 250 MW of demand response across about 80 installations in both fiscal years 2013 and 2014.[75]

---

[72] *Advanced Energy Economy & Sustainable FERC Project*, 167 FERC ¶ 61,032 (2019).

[73] DoD, Defense Logistics Agency Energy, *Fiscal Year 2018 Fact Book*, at 2, https://www.dla.mil/Portals/104/Documents/Energy/Publications/E_Fiscal2018FactBookLowRes.pdf?ver=2019-03-08-101941-663.

[74] *Id.* at 56.

[75] DoD, Defense Logistics Agency Energy, *Fiscal Year 2013 Fact Book*, at 60, https://www.dla.mil/Portals/104/Documents/Energy/Publications/DLA%20Energy%20Fact%20Book%202013_small.pdf?ver=2019-05-24-140027-470; and *Fiscal Year 2014 Fact Book*, at 52,

General Services Administration

The General Services Administration (GSA) manages centralized procurement for the Federal government, which includes providing energy services for agency workspaces in buildings that are either federally owned or leased.[76] In an effort to save taxpayers money by improving the efficiency of governmental operations, GSA has enabled the participation of facilities it manages in various demand response programs. GSA has enrolled approximately 25 MW of load in demand response programs and receives about $1 million in annual benefits.[77] GSA's current demand response participation largely takes place in the wholesale market programs NYISO and PJM manage, but GSA is also pursuing more opportunities to enroll buildings in utility-sponsored retail demand response programs in other regions.

Developments and issues in demand response

State legislative and regulatory activities related to demand response and time-based rates

In the past year, state regulators have directed electric utilities to expand time-based rate offerings in an effort to reduce peak demand, leverage advanced meter investments, and accommodate an increasing proliferation of distributed energy resources like electric vehicles and behind-the-meter battery storage systems. State regulators have shown a particular interest in establishing time-based rates for electric vehicle charging, aiming to establish clear price signals that will incentivize electric vehicle charging during off-peak periods. Additionally, electric utilities in a few states have proposed to implement demand response programs for residential customers that involve the utility temporarily taking direct control over a portion of the customer's load during times of grid stress.

- **California**. On July 11, 2019, the California Public Utilities Commission (CPUC) issued an order authorizing a four-year extension of the state's Demand Response Auction Mechanism (DRAM).[78] The CPUC authorized a pro-rated budget of $12.78 million for a 2019

---

https://www.dla.mil/Portals/104/Documents/Energy/Publications/E_Fiscal2014FactBookLowResolution_150911.pdf.

[76] GSA, "Background and History," https://www.gsa.gov/about-us/background-and-history.

[77] GSA, Update Federal Utility Partnership Working Group (Nov. 7, 2018), https://www.energy.gov/sites/prod/files/2018/11/f57/7-fupwg_fall_18_whiteman.pdf.

[78] *Application of Pacific Gas and Electric Company (U39E) for Approval of Demand Response Programs, Pilots and Budgets for Program Years 2018–2022*, Docket Nos. A. 17-01-012, -018, and -019, Decision Addressing Auction Mechanism, Baselines, And Auto Demand Response For Battery Storage (CPUC Jul. 11, 2019), http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M309/K713/309713644.PDF.

solicitation and an annual budget of $14 million for solicitations in 2020 through 2022.[79] The order also establishes several reforms to the DRAM program to improve competition, performance, and reliability among demand response providers. During their recent evaluation of the DRAM pilot program, the CPUC found that five demand response providers secured 94 percent of the total contract capacity through the first three annual auctions.[80] To increase the diversity of demand response providers, the CPUC established a ten percent set-aside for new market entrants in the DRAM solicitation. The regulators also instructed the utilities administering the program to establish a penalty structure for demand response providers that underperform.

In September 2018, California enacted a bill directing the CPUC to consider electric vehicle-specific tariffs that would incentivize off-peak charging and address demand charge issues associated with commercial electric vehicle charging stations.[81] On December 19, 2018, the CPUC established a new docket to develop a comprehensive framework to guide California's transportation electrification efforts.[82] The CPUC has either approved or considered new commercial electric vehicle charging rate proposals from each of the state's three investor-owned utilities within the last year on a case-by-case basis.[83] As part of its

---

[79] As noted in past reports, the CPUC directed the state's three investor-owned utilities to establish Demand Response Auction Mechanism pilots in 2016. The CPUC wanted to test the viability of using a competitive procurement mechanism for aggregated demand response resources to provide local, system, and flexible capacity. Recently, the CPUC evaluated the results of the first three years of the DRAM pilot program, and in the order mentioned above directed utilities to make structural reforms as part of a multi-year extension of the program. *See Assigned Commissioner's Amended Scoping Memo and Ruling*, Docket No. A1701012 (CPUC May 28, 2018), http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M214/K798/214798344.PDF.

[80] *Application of Pacific Gas and Electric Company (U39E) for Approval of Demand Response Programs, Pilots and Budgets for Program Years 2018–2022*, Docket Nos. A. 17-01-012, -018, and -019, Decision Addressing Auction Mechanism, Baselines, And Auto Demand Response For Battery Storage (CPUC Jul. 11, 2019) at 22–23.

[81] California State Legislature, *An Act to Add Section 65850.9 to the Government Code, to Add Section 25231 to the Public Resources Code, and to Add Section 740.15 to the Public Utilities Code, relating to Transportation Electrification*, SB 1000, https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201720180SB1000.

[82] *Order Instituting Rulemaking to Continue the Development of Rates and Infrastructure for Vehicle Electrification and Closing Rulemaking 13-11-007*, Docket No. R. 18-12-006, (CPUC Dec. 19, 2018), http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M252/K025/252025566.PDF.

[83] *See Application Of Southern California Edison Company (U 338-E) For Approval Of Its 2017 Transportation Electrification Proposals, Docket No. A. 17-01-021*, Decision on the Transportation Electrification Standard Review Projects, D-18-05-040 (CPUC Jun. 6, 2018), http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M215/K783/215783846.PDF ; *Application for Approval of Pacific Gas and Electric Company's Commercial Electric Vehicle Rate*, Docket No. A. 18-11-003, http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M238/K227/238227315.PDF; and *Application of San Diego Gas & Electric Company (U 902-E) for Approval of Senate Bill 350 Transportation Electrification Proposals Regarding Medium and Heavy-Duty Electric Vehicles and a Vehicle-to-Grid Pilot, Docket No. A. 18-01-012*, Decision Approving Settlement on Application, D. 19-08-026 (CPUC Aug. 15, 2019), http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M311/K550/311550050.PDF.

new proceeding, the CPUC's Energy Division is drafting a Transportation Electrification Framework that will include Zero Emission Vehicle rate design principles, which will lay the foundation for consideration of all future utility electric vehicle rate proposals.[84]

- **Connecticut**. On June 28, 2019, the governor of Connecticut signed HB No. 5002, which in part revised the state's electric utility restructuring law from 1998. The law carves out an exception for electric utilities to allow them to own, operate, and recover prudently-incurred costs from investments in energy storage systems.[85] Because energy storage systems are often used in demand response applications, this carve-out has the potential to increase the participation of demand response resources in the state.

- **District of Columbia**. On May 31, 2019, DC Public Service Commission (DC PSC) issued a final report on its recommendations under its grid modernization effort, referred to as Modernizing the Energy Delivery System for Increased Sustainability (MEDSIS). One of the recommendations calls for the DC PSC to reconvene a dynamic pricing working group that previously existed in the District. It further calls for PEPCO to develop residential dynamic pricing programs to be submitted for approval by the DC PSC in 2020, along with continuous monitoring of the dynamic pricing program to ensure that the program is effective.[86]

  On April 12, 2019, the DC PSC accepted in part an application by PEPCO to install electric vehicle infrastructure.[87] Specifically, the DC PSC approved PEPCO's residential TOU rate program designed for electric vehicle owners.[88] The DC PSC directed PEPCO to file detailed price information, so customers clearly understand the incentives for charging at off-peak hours.[89]

---

[84] *Assigned Commissioner's Scoping Memo and Ruling*, Docket No. R. 18-12-006, (CPUC May 2, 2018), http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M285/K712/285712622.PDF.

[85] State of Connecticut, *An Act Concerning a Green Economy and Environmental Protection*, HB No. 5002, https://www.cga.ct.gov/asp/CGABillStatus/CGAbillstatus.asp?which_year=2019&selBillType=Bill&bill_num=HB5002.

[86] *Final Report v1.0 of the DCPSC MEDSIS Stakeholder Working Groups* (May 31, 2019) at 119–123, https://edocket.dcpsc.org/apis/api/filing/download?attachId=84990&guidFileName=9d7f8ca1-7e89-4a46-8421-ab02a85ef4ec.pdf.

[87] Order No. 19898, Formal Case Nos. 1130, 1155 (DC PSC Apr. 12, 2019), https://edocket.dcpsc.org/apis/api/filing/download?attachId=84361&guidFileName=c302b307-c4b3-40e3-bf2e-3c8d9e064e64.pdf.

[88] *Id.* at 17–18.

[89] *Id.* at 18.

- **Maryland**. As mentioned in last year's report, the Maryland Public Service Commission (Maryland PSC) opened a proceeding in February 2018 to consider the implementation of an electric vehicle infrastructure portfolio.[90] On January 14, 2019, the Maryland PSC approved various electric vehicle charging station pilot programs proposed by the state's four investor-owned utilities, including a charger rebate program for residential customers that would incorporate an electric vehicle-only TOU rate.[91] The program provides rebates for customers to install "smart" residential electric vehicle chargers with communications and control capabilities similar to an advanced meter, and under the electric vehicle-only TOU rate the chargers would be treated as electric sub meters for billing and data sharing purposes.[92] BGE and PEPCO already had existing voluntary "whole house" TOU rates, and the Maryland PSC concluded that the utilities could also offer this full load TOU rate to customers participating in the residential charger rebate program.[93]

- **Michigan**. On June 4, 2019, DTE Energy, the largest utility in Michigan, announced a program called Charging Forward.[94] The utility's plan for the program, designed to combat the state's lagging electric vehicle adoption compared to other states, includes incentives to foster the development of electric vehicle infrastructure and electric vehicle adoption. Customers can qualify if they own an electric vehicle, install a certain type of charger, and enroll in a year-round TOU rate.[95] DTE Energy's program is designed to incentivize customers to charge their electric vehicles during off-peak times by using its existing TOU rates, in order to smooth out the demand on the grid.

- **Minnesota**. On July 17, 2019, the Minnesota PUC approved a proposal from Xcel Energy to deploy electric vehicle charging infrastructure as part of two new pilot programs that will

---

[90] *In The Matter Of The Petition of the Electric Vehicle Work Group for Implementation of a Statewide Electric Vehicle Portfolio,* Notice of Initiating A Proceeding and Request for Comments, Case Number 9478 (Maryland PSC, Feb. 6, 2018), http://webapp.psc.state.md.us/newIntranet/Casenum/CaseAction_new.cfm?CaseNumber=9478.

[91] *In The Matter Of The Petition of the Electric Vehicle Work Group for Implementation of a Statewide Electric Vehicle Portfolio*, Order 88997, Case Number 9478 (Maryland PSC Jan. 14, 2019), http://webapp.psc.state.md.us/newIntranet/Casenum/CaseAction_new.cfm?CaseNumber=9478.

[92] *Id.* at 50–52.

[93] *Id.* at 53–54.

[94] DTE, "DTE Energy Launches 'Charging Forward' Program to Drive Electric Vehicle Education, Infrastructure and Adoption" (Jun. 4, 2019), http://newsroom.dteenergy.com/2019-06-04-DTE-Energy-launches-Charging-Forward-program-to-drive-electric-vehicle-education-infrastructure-and-adoption#sthash.DQ2apJ1B.dpbs.

[95] DTE Energy customers have a choice between three types of rates: 1) EV Plan; 2) Time-of-Day Plan; and 3) Dynamic Peak Pricing Plan. *See* DTE, "Charging Forward," https://newlook.dteenergy.com/wps/wcm/connect/dte-web/home/service-request/residential/electric/pev/pev-res-charge-frwd.

employ time-varying rates, as required by Minnesota law.[96] One pilot will focus on charging infrastructure for electric vehicle fleet operators and the other will focus on public fast-charging stations.[97] Initially, customers participating in either pilot will be charged under Xcel Energy's existing general service time-of-day rate, which utilizes a single 12-hour peak period. However, as part of the order approving the pilot programs, the Minnesota PUC directed Xcel Energy to file a new commercial electric vehicle charging tariff within six months, "that is more reflective of hourly system costs with a price signal designed to reduce peak demand."[98]

On May 16, 2019, Minnesota Power submitted a proposal for an electric vehicle charging rate pilot program for commercial and industrial customers.[99] Minnesota Power notes in its proposal that high demand charges are one of the biggest obstacles to expanding electric vehicle charging among its large industrial customer base, and the pilot proposal is structured to mitigate these issues.[100] The pilot would establish new time-based demand charges: participating customers would not be assessed any demand charge for off-peak charging, and demand charges for on-peak charging would be capped at 30 percent of the customer's total bill.[101]

- **Missouri**. On December 5, 2018, the Missouri PSC approved Ameren Missouri's revised Missouri Energy Efficiency Act Cycle 3 plan, which covers 2019–2021.[102] The revised plan includes new residential and business demand response programs. The residential demand

---

[96] Minn. Stat. § 216B.1614 requires that EV charging tariffs "appropriately reflect off-peak versus peak cost differences in the rate charged."

[97] *Order Approving Pilots With Modifications, Authorizing Deferred Accounting, And Setting Reporting Requirements*, Docket No. E-002/M-18-643 (Minnesota PUC Jul. 17, 2019) at 22, https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={D017016C-0000-CD10-8791-F2FF6B5C1546}&documentTitle=20197-154444-01.

[98] *Id.* at 22.

[99] *Petition for Approval of Electric Vehicle Commercial Charging Rate Pilot*, Docket No. E015/M-19-337, (Minnesota Power Jul. 19, 2019), https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={80FDC16A-0000-CF11-87CD-7F09E1CECE99}&documentTitle=20195-152973-01.

[100] *Id.* at 3.

[101] *Id.* at 12–16.

[102] *In The Matter of Union Electric Company D/B/A Ameren Missouri's 3rd Filing to Implement Regulatory Changes in Furtherance of Energy Efficiency as Allowed by Meeia*, Order Approving Stipulation and Agreement and Granting Waivers, Docket No. EO-2018-0211, (Missouri PSC Dec. 5, 2018), https://www.efis.psc.mo.gov/mpsc/commoncomponents/view_itemno_details.asp?caseno=EO-2018-0211&attach_id=2019007937.

response program will provide incentives to customers with smart thermostats to reduce consumption during summer system peak conditions.[103] On April 9, 2019 Ameren Missouri signed an agreement with Enel X to coordinate the business demand response program and deliver 100 MW of demand response capacity from commercial and industrial customers in the utility's service territory.[104]

- **New Hampshire**. On January 31, 2019, the New Hampshire Public Utilities Commission (New Hampshire PUC) issued a staff report with recommendations on grid modernization.[105] After consulting with DOE and analyzing grid modernization efforts in other states, New Hampshire PUC staff recommended that the state's electric utilities be required to develop and submit integrated distribution plans, which would incorporate grid modernization principles identified in the report. The integrated distribution plan development process would supplant the current least cost integrated resource planning process.[106] New Hampshire PUC staff recommended that future integrated distribution plan proposals discuss of how time-varying rates and demand response can reduce system costs and help ratepayers lower their own costs.[107]

  In addition, on January 17, 2019, the New Hampshire PUC approved a settlement agreement for Liberty Utilities to implement a customer-sited battery storage pilot program that incorporates new time-varying rates.[108] Participating customers will be required to switch to a new TOU service with critical peak, mid-peak and off-peak pricing periods.[109] Liberty Utilities plans to control the batteries at certain times to limit system peak load and reduce transmission charges assessed by ISO-NE; otherwise customers will be able to use the batteries to shift their load away from peak hours and reduce their electricity bill through

---

[103] *Revised Ameren Missouri's 2019–21 Energy Efficiency Plan*, Docket No. EO-2018-0211, (Ameren Missouri Dec. 5, 2018), https://efis.psc.mo.gov/mpsc/commoncomponents/viewdocument.asp?DocId=936195031.

[104] Enel X, "Enel X Signs 100 MW Demand Response Agreement with Ameren Missouri" (Apr. 2019), https://www.enelx.com/n-a/en/news-media/all-press/enel-x-signs-100mw-demand-response-agreement-ameren-missouri.

[105] *Staff Recommendation on Grid Modernization*, Docket No. IR 15-296 (New Hampshire PUC Feb. 12, 2019), https://www.puc.nh.gov/Regulatory/Docketbk/2015/15-296/LETTERS-MEMOS-TARIFFS/15-296_2019-02-12_STAFF_REPORT_AND_RECOMMENDATION.PDF.

[106] *Id.* at 21–22.

[107] *Id.* at 56.

[108] *Order No. 26,209 Approving Settlement Agreement and Implementation of Pilot Program and Granting Motions for Confidential Treatment*, Docket No. DE 17-189 (New Hampshire PUC Jan. 17, 2019), https://www.puc.nh.gov/Regulatory/Docketbk/2017/17-189/ORDERS/17-189_2019-01-17_ORDER_26209.PDF.

[109] *Id.* at 21.

the new TOU structure. The New Hampshire PUC authorized Liberty Utilities to deploy up to 200 batteries during Phase 1 of the pilot program, growing to 500 batteries in Phase 2 if the utility shows that the first phase was successful and cost-effective.[110]

- **New York**. On December 13, 2018, the New York Public Service Commission (NY PSC) approved a proposal from Consolidated Edison (Con Ed) to establish an Innovative Pricing Pilot.[111] The pilot will test new rate structures that adjust the delivery and supply charge components of a customer's bill based on its usage during on/off-peak periods.[112] Con Ed expects to enroll approximately 67,000 residential and small commercial customers in the pilot, the majority of which will enroll on an opt-out basis. The pilot will also include a one-year price guarantee, so customers whose bills are higher under the new rate structures for their first twelve months of service will receive a credit based on what they would have been charged under their previous rate.[113]

- **North Carolina**. As mentioned in last year's report, the North Carolina Utilities Commission (NCUC) approved cost recovery for full deployment of advanced meters throughout Duke Energy Carolinas' (DEC) service territory in June 2018, and required that DEC propose new rate structures to capture the full benefits of advanced meters.[114] Following that order, DEC proposed a multi-year timeline to prepare analytical tools, collect data, and develop new dynamic rate designs enabled by advanced meters.[115] In January 2019, NCUC issued an order rejecting the proposed rate design plan and directing DEC to "significantly accelerate" its timeline for designing time-varying rates to ensure customers are able to realize the benefits of advanced meter deployment as soon as practicable.[116]

---

[110] *Id.* at 18.

[111] *Tariff Filing by Consolidated Edison Company Of New York, Inc. to Make Revisions to Its Electric Tariff Schedule, P.S.C. No. 10, to Add New Riders Z (Residential) and Aa (Small Commercial) Innovative Pricing Pilot, to Implement Rate Structures for Residential and Small Commercial Customers*, Order Approving Tariff Amendments With Modifications, Docket No. 18-E-0397 (NY PSC Dec. 13, 2018), http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={47B467E0-8F7B-4F3E-9FE3-45925277A16F}.

[112] *Id.* at 3–6.

[113] *Id.* at 7.

[114] FERC, *Assessment of Demand Response and Advanced Metering*, at 10 (2018), https://www.ferc.gov/legal/staff-reports/2018/DR-AM-Report2018.pdf.

[115] *Duke Energy Carolinas, LLC Rate Design Report*, Docket No. E-7, Sub 1146 (DEC Dec. 21, 2018), https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=f07ba79d-a9b1-410a-8895-b2beaa36335c.

[116] *Order Declining to Accept Rate Design Plan, Requiring Compliance Filing, Scheduling Hearing, and Requiring Coordination with Public Staff*, Docket No. E-7, Sub 1146 (NCUC Jan. 30, 2019) at 4–5, https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=12af76f3-f507-4352-92ec-32facb7eaba0.

On July 2, 2019, the NCUC approved a revised proposal from DEC to implement a pilot to test nine new time-varying rate structures.[117] DEC will evaluate how residential and small general service customers respond to critical peak and daily peak pricing structures by pilot testing each rate for a minimum of 12 months with approximately 500 customers.[118] DEC plans to use the information gained from this pilot to develop dynamic (or real-time) rates that the utility will introduce to all its customers shortly after deploying its new Customer Connect billing system in Spring 2021.[119]

- **Oregon**. At a public meeting on April 9, 2019,[120] the Oregon Public Utilities Commission (Oregon PUC) approved Portland General Electric's (PGE) proposed demand response pilot program.[121] PGE's proposal, in compliance with the Oregon PUC's Order No. 17-386,[122] will establish a residential demand response pilot program for 20,000 customers served by three specific substations. The program will offer a peak time rebate to all customers (who do not opt out) who reduce their electricity use during peak demand periods, to be determined by PGE by 4:00 p.m. on the day before the peak.[123] Additionally, PGE will offer customers an opt-in to a direct load control program in exchange for a lower rate structure.[124] The pilot is set to continue through June 30, 2022.[125]

---

[117] *In the Matter of Application of Duke Energy Carolinas, LLC, for Approval of Time-of-Use Pilots, Order Approving Pilots*, Docket No. E-7, Sub 1146 (NCUC Jul. 2, 2019), https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=855bf4e4-b50b-4fe7-8b1f-cbe60599b4d7.

[118] *Duke Energy Carolinas, LLC's Revised AMI Rate Design Work Plan and Proposed Dynamic Pricing Pilots*, Docket No. E-7, Sub 1146 (DEC Apr. 2, 2019) at 2–3, https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=ceff9e7f-7247-42d8-8367-8a468e3c6d93.

[119] *Id.* at 2, 5, 8.

[120] *Oregon PUC Minutes of Public Meeting*, (Apr. 9, 2019) at 2, http://oregonpuc.granicus.com/DocumentViewer.php?file=oregonpuc_2dd1a19ff96a18c77c8a9380bf980000.pdf&view=1.

[121] *PGE Application for Approval*, Advice No. 18-14 (Oct. 25, 2018), https://edocs.puc.state.or.us/efdocs/UAA/uaa173123.pdf.

[122] The order directed PGE to: Establish a demand response test bed by July 1, 2019; establish a Demand Response Review Committee to assist in the development and success of PGE's demand response activities including review of PGE's proposals for demand response programs; and acquire at least 77 MW of winter and 69 MW of summer demand response capacity through 2020. Order No. 17-386 (Oregon PUC Oct. 7, 2017), https://apps.puc.state.or.us/orders/2017ords/17-386.pdf.

[123] *PGE Application for Approval*, Advice No. 18-14 (Oct. 25, 2018) at 13-1.

[124] *Id.* at 1.

[125] *Id.* at 13-3.

- **Utah**. On June 28, 2019, the Public Service Commission of Utah (Utah PSC) approved several demand response programs proposed by Rocky Mountain Power. One of the approved projects is a battery demand response project proposed in partnership with Wasatch Development.[126] The approved project includes the installation of individual batteries in each unit of a 600-unit, 22-building, multi-family development in Herriman, Utah.[127] Rocky Mountain Power will have full control to deploy the solar-charged batteries for system-wide demand response.[128]

- **Vermont**. On December 21, 2018, the Vermont Public Utility Commission (Vermont PUC) approved a Tesla Powerwall 2.0 pilot program proposed by Green Mountain Power.[129] The program offers customers a Tesla Powerwall unit for a discounted one-time charge of $1,500, or a monthly charge of $15 for 10 years.[130] In exchange for this rebate, customers give Green Mountain Power control over the units to manage system-wide or local peak conditions.[131]

---

[126] *In the Matter of the Application of Rocky Mountain Power to Implement Programs Authorized by the Sustainable Transportation and Energy Plan Act*, Report and Order, Docket No. 16-035-36 (Utah PSC Jun. 28, 2019), https://pscdocs.utah.gov/electric/16docs/1603536/3089131603536rao6-28-2019.pdf.

[127] *Id.* at 3.

[128] *Id.*

[129] *Tariff Filing of Green Mountain Power Corporation*, Case No. 18-0974-TF (Vermont PUC Dec. 21, 2019), https://epuc.vermont.gov/?q=downloadfile/323902/130760.

[130] *Id.* at 9.

[131] *Id.* at 8–12.

VI. Regulatory barriers to improved customer participation in demand response, peak reduction, and critical period pricing programs

The 2009 National Assessment of Demand Response Potential[132] and previous annual staff reports describe the barriers to customer participation in demand response programs. Outstanding barriers and recent actions taken to address them are presented below.

- **Implementing Time-based Rates**. One of the principal barriers to customer participation in demand response is relatively slow implementation of time-based rate programs. As noted in Chapter 5, adoption of time-based rates continues to increase, driven by utility and regulator interest in leveraging existing and proposed advanced meter deployment and by burgeoning recognition of the need to incentivize charging of electric vehicles and other distributed energy resources at off-peak periods. Recent research supports the conclusion that many customers will reduce their electricity consumption in response to price changes.[133]

  As described above, retail customer enrollment in time-based rate programs increased by approximately seven percent in 2017 from a year earlier. However, while customer participation in time-based rate programs has increased every year since 2013, only 8.5 million customers were participating in such programs as of 2017 – still a relatively small percentage of all retail customers.

  In recent surveys, utilities have expressed interest in using time-based rates and other means to manage the charging of electric vehicles. For example, the Smart Electric Power Alliance (SEPA) identifies 28 utility managed charging projects for electric vehicles that are currently active in the United States, and another ten that have recently been completed or are in the planning stages. In addition, 53 percent of respondents to SEPA's survey indicated an interest in demand response programs involving managed charging of electric vehicles, compared to 26 percent of respondents with no interest.[134] Further, as noted above, in the

---

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

[133] A study based on data from more than 250 homes in Austin, TX, found that participants in the pricing treatment group responded to critical peak pricing by reducing their electricity use during event hours by 14 percent. *See* Burkhardt, J., et al., *Experimental Evidence on the Effect of Information and Pricing on Residential Electricity Consumption* (Feb. 2019) at 2–3, https://ssrn.com/abstract=3336385.

[134] Managed charging refers to passive (e.g., time-based rates) and active (e.g., direct load control) means of altering the time, magnitude, or location at which grid-connected electric vehicles charge or discharge. *See* SEPA, *A Comprehensive*

last year several public service commissions – including those in Maryland, Michigan, Minnesota, New York, North Carolina, and the District of Columbia – have approved or are proposing to require development of time-based rates, some of them to address integration of electric vehicles into their systems.

New research from the Brattle Group estimates the potential of "load flexibility"[135] from many distributed technologies – including smart appliances, electric vehicle managed charging, and advanced meters – to provide additional services beyond peak capacity reductions in order to meet evolving system needs. The Brattle Group's report estimates that nationwide potential for load flexibility could total approximately 200 GW by 2030, and that the most significant cost-effective potential lies in dynamic pricing programs across all customer segments, as well as residential smart thermostat programs.[136] Further, the report suggests that realizing a large portion of this load flexibility potential primarily requires modernizing existing conventional demand response programs with updated program designs (such as transitioning switch-based direct load control programs to smart-thermostat programs) and customer engagement practices. Other supporting policies, technology standards, regulatory incentives, and analytical methods may also play a role in realizing this load flexibility potential.[137]

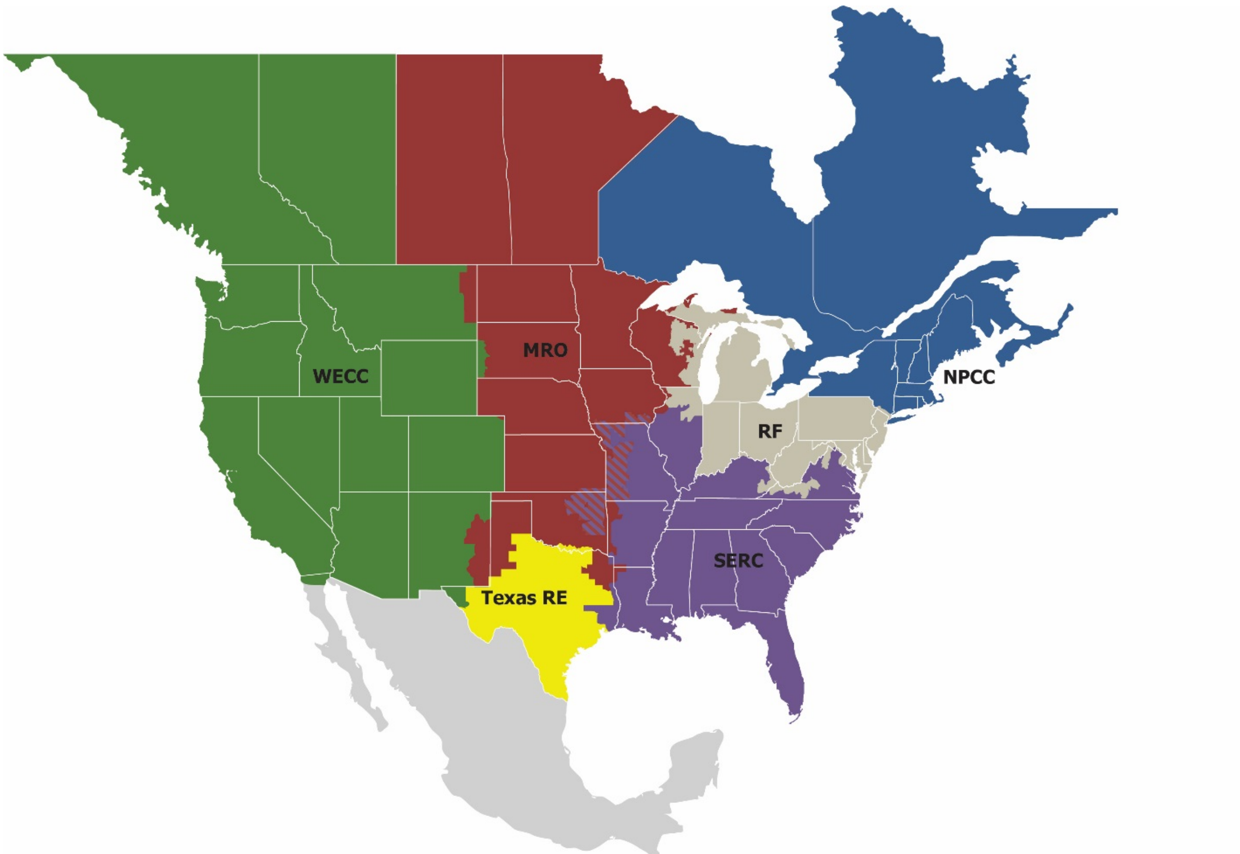
Guide to Electric Vehicle Managed Charging (May 2019) at 11, 16–17, and Appendix A, https://sepapower.org/resource/a-comprehensive-guide-to-electric-vehicle-managed-charging/.

[135] Load flexibility refers to load management activities – mediated through emerging consumer technologies – that provide additional services beyond the type of peak demand reduction historically provided by demand response. These additional services include geographically-targeted demand reductions that defer or avoid new transmission and distribution capacity, load shifting and load building, and ancillary services. *See* The Brattle Group, *The National Potential for Load Flexibility: Value and Market Potential Through 2030* (Jun. 2019), at 1, 13, https://brattlefiles.blob.core.windows.net/files/16639_national_potential_for_load_flexibility_-_final.pdf.

[136] *Id.* at 2.

[137] *Id.* at 2, 25.

Appendix: Map of NERC Regional Entities



Note: On May 4, 2018, FERC approved a joint petition to dissolve the SPP RE and transfer NERC registered entities within the SPP RE footprint to MRO and SERC, effective July 1, 2018. *See NERC, MRO and SERC*, 163 FERC ¶ 61,094 (2018). In addition, on April 30, 2019, FERC approved a separate joint petition to dissolve FRCC as a Regional Entity and transfer NERC registered entities within the FRCC footprint to SERC, effective July 1, 2019. *See NERC, FRCC, and SERC*, 167 FERC ¶ 61,095 (2019). A map of the eight previous NERC regions is here: https://www.nerc.com/AboutNERC/keyplayers/PublishingImages/New%20Regions%20map%20no%20FRCC.jpg.

2019 Assessment of
Demand Response and Advanced Metering

Staff Report
Federal Energy Regulatory Commission
December 2019