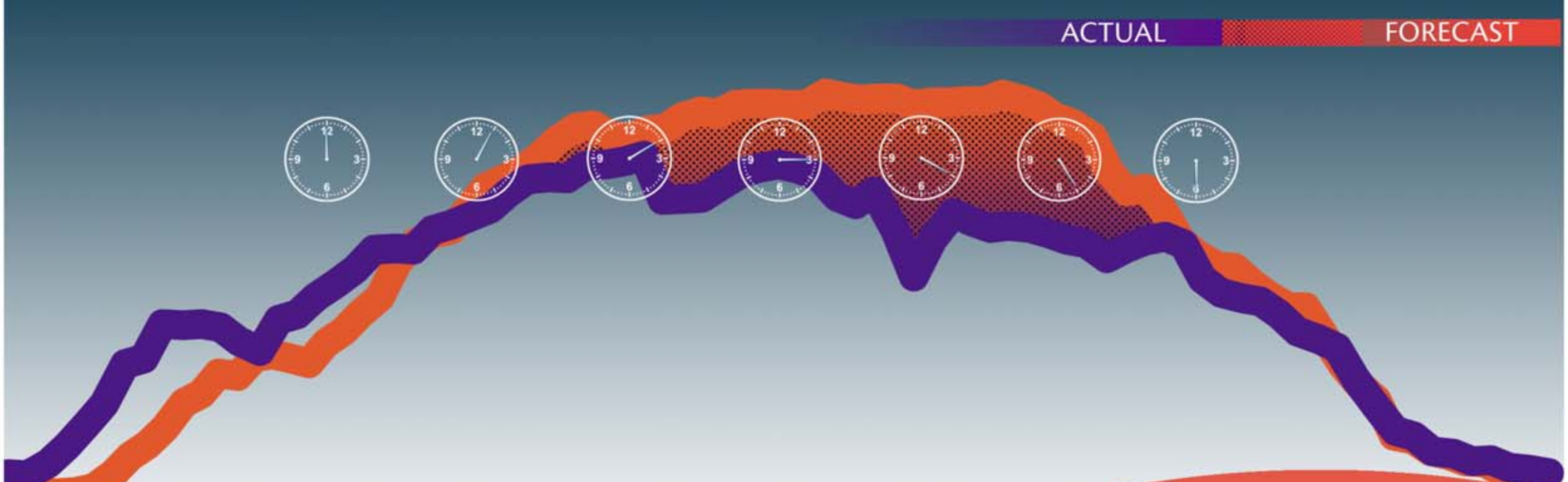
FEDERAL ENERGY REGULATORY COMMISSION

ASSESSMENT OF Demand Response & Advanced Metering

STAFF REPORT



FEBRUARY 2011

2010

Assessment of
Demand Response and Advanced Metering

Staff Report

Federal Energy Regulatory Commission

February 2011

ACKNOWLEDGEMENTS

Federal Energy Regulatory Commission Staff Team

Dean Wight, Team Lead
Caroline Daly
David Kathan
Michael P. Lee
Kamaria Martin
Pamela Silberstein
Michael Tita
Rebecca Vertes

Z, INC. Team

Bryan Templeton (Z, INC.)
Valerie Richardson (KEMA)
Will Gifford (KEMA)
Christopher Elsner (Z, INC.)
Matthew S. Pettit (KEMA)
Geoff Barker (KEMA)
Ron Chebra (KEMA)

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

EXECUTIVE SUMMARY

Results of the 2010 Advanced Metering and Demand Response Survey

Advanced metering penetration and potential peak load reductions from electric power demand response have increased significantly since 2008.

The Federal Energy Regulatory Commission's 2010 Demand Response and Advanced Metering Survey (2010 FERC Survey, covering calendar year 2009) indicates that advanced metering penetration (i.e., the fraction of all installed meters that are advanced meters) reached approximately 8.7 percent in the United States, compared to approximately 4.7 percent in the 2008 FERC Survey (covering calendar year 2007). The upper Midwest, West and Texas have advanced meter penetrations exceeding 13 percent. As in previous surveys, electric cooperatives have the largest penetration, nearly 25 percent, among categories of organizations.

In response to the 2010 FERC Survey, more than 500 entities reported offering demand response programs in the United States. The potential demand response resource contribution from all U.S. demand response programs is estimated to be more than 58,000 megawatts (MW), or about 7.6 percent of U.S. peak demand. This is an increase of about 17,000 MW from the 2008 FERC Survey. The regions with the largest estimated demand response resources are the Midwest-to-Mid-Atlantic region, and also the Upper Midwest and the Southeast**.**

Demand Response Developments and Barriers

Demand response is facilitated through programs undertaken by electric utilities and demand response providers as well as through state and federal programs. For example, federal funding for advanced meters became available under the American Recovery and Reinvestment Act, and the Federal Energy Regulatory Commission issued the *National Action Plan on Demand Response* in June 2010—a plan which sets out actions to achieve the demand response potential in the United States.

Activities to address regulatory barriers to demand response include state policy changes to reduce the financial effects of demand response on utilities, efforts to improve and standardize methods for measuring baseline electric use, the revision of wholesale market rules to remove barriers to participation by demand response resources, industry efforts to assess the cost-effectiveness of demand response, the FERC-NARUC smart response collaborative, and the development of interoperability standards for smart meters.

CHAPTER 1. INTRODUCTION

The Energy Policy Act of 2005 (EPAct 2005) requires the FERC to prepare pertinent data and publish an annual report on the penetration of advanced metering and demand response programs in the electric power industry in the United States. This data is to be divided and presented by region and the information is to cover all types of electric consumer.

EPAct 2005 expressly requires the Commission to quantify and review:

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

Prior Reports in This Series

In August 2006 Commission staff published the first in this series of reports, *Assessment of Demand Response and Advanced Metering.*[1] This comprehensive report was based on a first-of-its-kind survey of demand response and advanced metering. In 2007, the Commission staff published a second report,[2] emphasizing results, industry activities, and regulatory actions taken since the previous report. The 2007 report noted that FERC staff would conduct, analyze, and report on the results of a comprehensive nationwide survey every other year, with intervening years' reports consisting of updates based on publicly available information and discussions with market participants and industry experts. Staggering the reporting in this way allows FERC staff to provide a more informed analysis in each bi-yearly survey-based report while still reporting on demand response and advanced meters annually. A second survey (referred to here as the 2008 FERC Survey) was conducted in 2008 and gathered data for calendar year 2007. The results were reported in the 2008 *Assessment of Demand Response and Advanced Metering.*[3] In September 2009 staff published the fourth report, based like the 2007 report on public information and

[1] FERC, *Assessment of Demand Response & Advanced Metering: Staff Report*, Docket No. AD06-2, August 7, 2006, *available at* http://www.ferc.gov/industries/electric/indus-act/demand-response.asp.
[2] FERC, *Assessment of Demand Response & Advanced Metering*: *Staff Report*, September 2007, *available at* http://www.ferc.gov/industries/electric/indus-act/demand-response.asp.
[3] FERC, *Assessment of Demand Response & Advanced Metering*: *Staff Report*, December 2008, *available at* http://www.ferc.gov/industries/electric/indus-act/demand-response.asp.

conversations with industry participants, and also drawing upon FERC's *National Assessment of Demand Response Potential*[4] published in June 2009.

Preparation of This Year's Report

In preparing this report, Commission staff undertook several activities, the most significant of which was the preparation and release of the 2010 Demand Response and Advanced Metering Survey (2010 FERC Survey), and analysis of the survey responses. As with previous surveys, the 2010 FERC Survey gathered data for the preceding calendar year, 2009.

Commission staff also reviewed the literature and regulatory developments in advanced metering and demand response programs including time-based rates since the publication of the 2009 report.

Demand Response and Advanced Metering Survey

The 2010 FERC Survey was conducted in the first half of 2010 with the help of Z, INC. and KEMA. The survey requested (a) general information about the respondent, including contact information; (b) the number of advanced meters and the number of total meters; (c) existing demand response and time-based rate programs, including their current level of resource contributions, and (d) near and medium-term plans for demand response programs. The 2010 FERC Survey combined the separate Advanced Metering Infrastructure (AMI) and Demand Response surveys of previous years into one.

Responses to the survey were requested from 3,454 entities in all 50 states and representing all aspects of the electricity delivery industry: investor-owned utilities, municipal utilities, rural electric cooperatives, power marketers, state and federal agencies, and demand response providers.[5] Later in the process it was determined that 96 of these entities were either out of business or not in a relevant business.

Of the remaining 3,358 entities, 1,755 responded to the 2010 FERC Survey (a response rate over 52 percent). These 1,755 entities serve 112 million electric customers, which is over 77 percent of the 145 million customers served nationally. For comparison, the 2008 FERC Demand Response Survey response rate was 60 percent, and the 2008 FERC AMI Survey response was 55 percent.

Information gathered through the survey serves as the basis for this report's data on the penetration[6] of advanced metering, the information on existing demand response and time-based rate programs, and demand response resource contributions. In addition, the results of the 2008 and 2006 FERC Surveys provide a time series of data on advanced metering penetration and the level of demand response capability in the United States.

[4] FERC, *A National Assessment of Demand Response Potential: Staff Report*, June 2009; available at http://www.ferc.gov/industries/electric/indus-act/demand-response/dr-potential/assessment.asp.
[5] Appendices D and H include detailed information on the survey and sample design. Appendix E lists the respondents to the survey.
[6] Penetration, for the purposes of this report, refers to the ratio of advanced meters to all installed meters.

Report Organization

The report begins with this **Introduction**, which describes the report structure. The following chapters provide the information required by EPAct 2005 section 1252(e)(3).

Advanced Metering Infrastructure presents the survey results on the penetration of advanced metering nationally, regionally, by type of utility, customer class, and by state. This chapter also discusses developments and issues in the deployment and adoption of advanced metering.

Demand Response presents the survey results on demand response programs, including time-based rate programs, and gives the regional and national distribution of these programs, as measured by the number of enrolled customers reported in the 2010 FERC Survey. This chapter also uses the 2010 FERC Survey data to estimate the level of demand response in the United States. The chapter then reviews demand response developments at the national and state level, and summarizes and analyzes barriers to demand response.

Eight **appendices** provide reference material and additional detail on the 2010 FERC Survey and survey respondents. **Appendix A** lists the statutory language in section 1252 of EPAct 2005. **Appendix B** lists the acronyms used in this report. **Appendix C** contains a glossary of the key terms used in this report and the 2010 FERC Survey. **Appendix D** presents additional detail on the 2010 FERC Survey and documents survey response rates. **Appendix E** lists the respondents to the 2010 FERC Survey. **Appendix F** lists the entities that indicate that they operate demand response programs in their responses to the 2010 FERC Survey. **Appendix G** provides data tables for each of the figures in this report. **Appendix H** explains the methodology used to estimate values for nonrespondents.

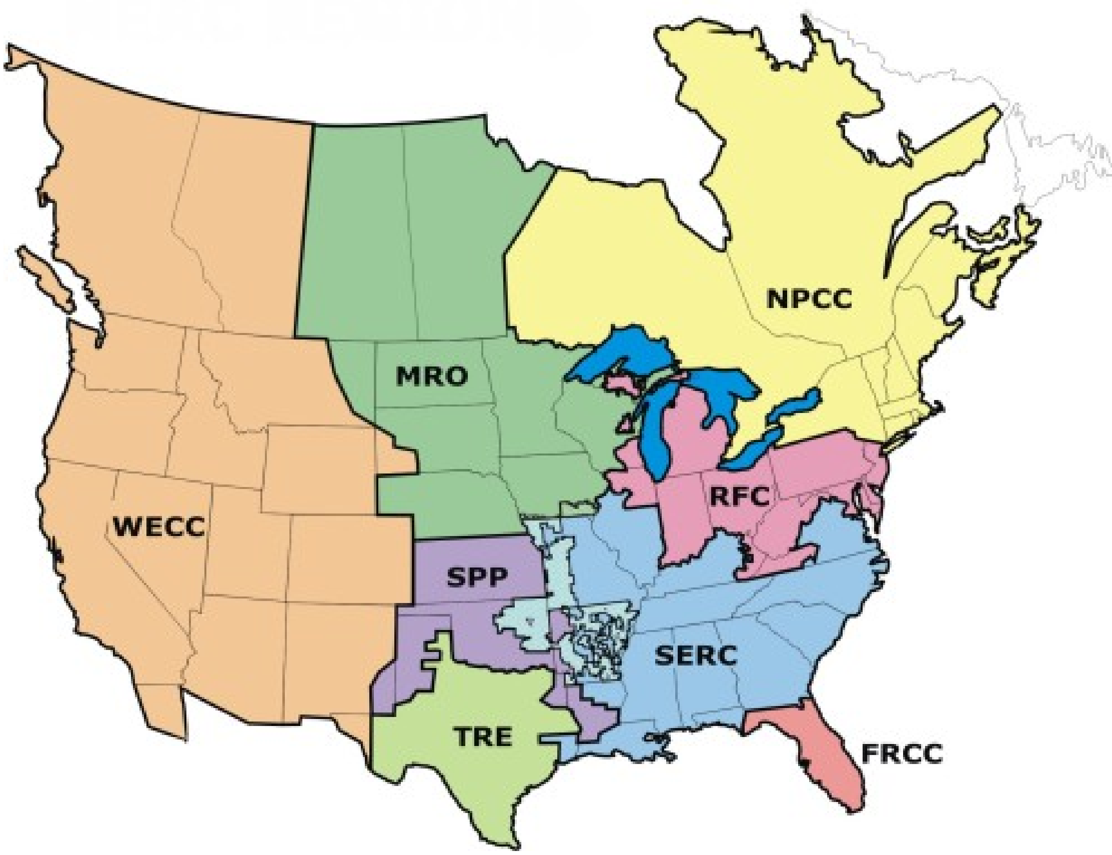
Regions in This Report

The North American Electric Reliability Council (NERC) is an international nonprofit organization certified by the FERC as the electric reliability organization for the U.S. NERC works with eight regional entities, each composed of members from all segments of the electric industry. The 2010 FERC Survey comprises the U.S. domestic area of the NERC regional entities, and uses the regional divisions to better identify trends and align regulatory and industry geographical units. The regional entities are:

- Florida Reliability Coordinating Council (FRCC)
- Midwest Reliability Organization (MRO)
- Northeast Power Coordinating Council (NPCC)
- Reliability*First* Corporation (RFC)
- SERC Reliability Corporation (SERC)
- Southwest Power Pool (SPP)
- Texas Reliability Entity (TRE)
- Western Electricity Coordinating Council (WECC)

In this report, Hawaii and Alaska are not included in most regional data listings, but are shown in state-by-state data. The map in Figure 2.1 shows the boundaries of these regional entities.

Figure 2.1. NERC Regions



FRCC - Florida Reliability Coordinating Council
MRO - Midwest Reliability Organization
NPCC - Northeast Power Coordinating Council
RFC - Reliability*First* Corporation
SERC - SERC Reliability Corporation
SPP - Southwest Power Pool
TRE - Texas Reliability Entity
WECC - Western Electricity Coordinating Council

Source: North American Electric Reliability Corporation.

CHAPTER 2. ADVANCED METERING INFRASTRUCTURE

This chapter reports on the first topic in EPAct 2005 section 1252(e)(3):

(A) saturation and penetration rates of advanced meters and communications technologies, devices and systems.

The information presented on advanced metering penetration is based on the 2010 FERC Survey with some comparisons to 2006 and 2008 FERC survey information to demonstrate trends in advanced metering placement on a regional basis, by type of entity, and by customer type.

The information in the chapter provides summary-level data on penetration rates of advanced metering survey results. A database of survey responses is available online at http://www.ferc.gov/industries/electric/indus-act/demand-response/dem-res-adv-metering.asp

This chapter has three sections:

- Definition of Advanced Metering
- Summary of Advanced Metering penetration
- Developments and Issues in Advanced Metering

Definition of Advanced Metering

For the 2010 FERC Survey, FERC staff modified the definition for advanced meters to be consistent with that used by the Energy Information Administration (EIA). The definition of advanced meters used in the survey and this report is:

> **Advanced Meters**: Meters that measure and record usage data at hourly intervals or more frequently, and provide usage data to both consumers and energy companies at least once daily. Data are used for billing and other purposes. Advanced meters include basic hourly interval meters, meters with one-way communication, and real-time meters with built-in two-way communication capable of recording and transmitting instantaneous data.

The modified definition resulted in changes in advanced meter counts by some entities responding to the 2010 Survey compared to the 2008 and 2006 FERC Surveys. In follow-up calls, staff learned that three respondents reclassified meters previously reported as advanced meters to non-advanced meters because of the new requirement of "providing customers with usage data at least once daily." For this reason the utility serving Jacksonville, FL, (JEA) reduced its advanced meter count from nearly 400,000 in the 2008 FERC Survey to zero in the 2010 FERC Survey.

Summary of Advanced Metering Penetration Results

This section describes the design of the advanced metering portion of the 2010 FERC Survey, the approach used to analyze the results, and summary findings of the survey and analysis.

2010 FERC Survey Design

The 2010 FERC Survey contained AMI questions nearly identical to those in the 2006 and 2008 FERC AMI Surveys, with these exceptions: (1) the 2010 FERC Survey's definition for advanced meters was changed from the definition used in 2008; and (2) the 2010 FERC Survey asked only for the methods of communicating AMI data to customers (while previous surveys asked how the advanced meters were being used, e.g., for enhanced customer service, outage detection). FERC staff made these changes to be consistent with EIA, as discussed above, and to simplify the voluntary survey and encourage responses.

Analysis Approach

The findings presented here include estimated values that are extrapolations of survey results to states, regions, the United States, and types of entity. **Appendix H** provides a detailed explanation of the analysis and extrapolation approach. Also presented are the reported (not extrapolated) numbers of customers and communications methods for advanced metering.

In this and following chapters, figures and tables with results compiled directly from data submitted by survey respondents without estimation of results for those not reporting are labeled "Reported" or "Reporting." Figures and tables with results that include both data submitted by survey respondents and estimation of results for those not reporting, based on survey and other information, are labeled "Estimated."

Survey Findings

The 1,755 responding entities report serving 112 million electric customers, which is over 77 percent of the 145 million customers served nationally. The response rate for the 2010 FERC Survey on an entity basis was 52 percent, slightly less than the previous two surveys. Small entities (mostly municipally owned utilities) had a response rate of about 47 percent. For large and medium size entities, the response rates were about 84 percent and 70 percent, respectively.

The survey results present robust growth in advanced metering nationally. As indicated in Figure 3.1, estimated advanced metering penetration increased to 8.7 percent in 2009 versus 4.7 percent in 2007, an 85 percent increase in penetration in two years.

Figure 3.1. Estimated advanced metering penetration nationwide in 2006, 2008 and 2010 FERC Surveys

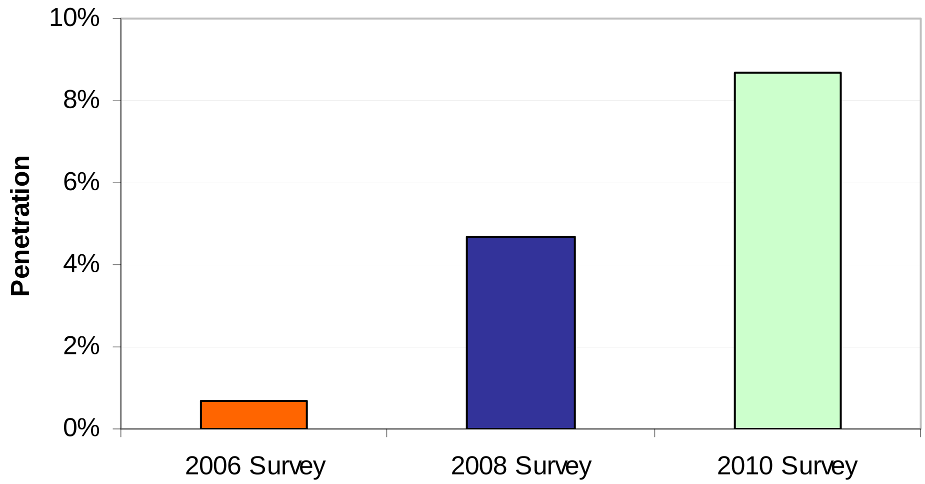
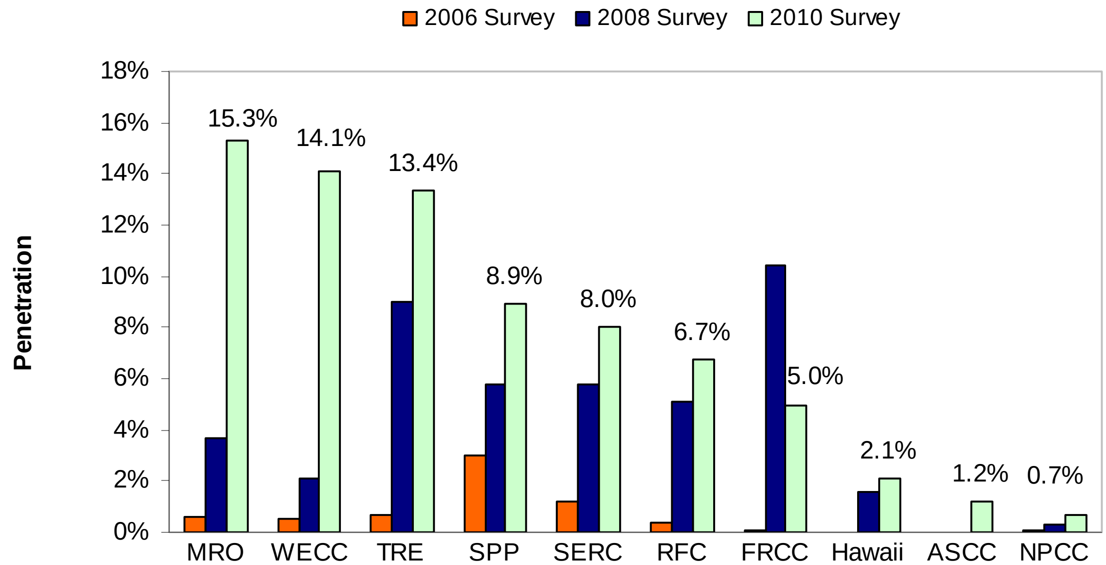


Figure 3.2 provides the estimated penetration of advanced meters by NERC region. MRO, WECC and TRE regions have penetrations exceeding 13 percent, although penetration of advanced meters remains below 20 percent in all regions. Growth was especially rapid in WECC and MRO where penetrations increased six-fold and four-fold, respectively, from 2007 to 2009. The increase in WECC may reflect the rollout of advanced meters in California where the IOUs have collective targets of over 15 million advanced meters by 2012. The increase in TRE can be attributed to the regulatory environment in this active competitive retail access state. Advanced metering penetration declined only in FRCC, where JEA, the Jacksonville utility, reclassified nearly 400,000 meters from advanced to non-advanced because of the change in the survey's advanced metering definition.

Figure 3.2. Estimated advanced metering penetration by region in 2006, 2008 and 2010 FERC Surveys



	MRO	WECC	TRE	SPP	SERC	RFC	FRCC	Hawaii	ASCC	NPCC
2006 Survey	0.6%	0.5%	0.7%	3.0%	1.2%	0.4%	0.1%	0.0%	0.0%	0.1%
2008 Survey	3.7%	2.1%	9.0%	5.8%	5.8%	5.1%	10.4%	1.6%	0.0%	0.3%
2010 Survey	15.3%	14.1%	13.4%	8.9%	8.0%	6.7%	5.0%	2.1%	1.2%	0.7%

Region

The number of advanced meters for residential customers grew notably in WECC, MRO, TRE and SPP. The completion of pilot programs and early ramp-up efforts is giving way to a "production mode" with mass market characteristics. Nationally, advanced metering penetration for residential customers increased to nearly 9 percent, and to 7 percent for nonresidential customers. Table 3.1 provides the estimated penetration of advanced meters by customer class reported in the 2006, 2008 and 2010 FERC Surveys.

Table 3.1. Estimated advanced metering penetration by region for residential and nonresidential customers

	Advanced Metering Penetration (percent)								
	All Meters			Residential Meters			Nonresidential Meters		
FERC Survey Region	2006	2008	2010	2006	2008	2010	2006	2008	2010
MRO	0.6	3.7	15.3	0.5	4.0	15.8	1.1	2.2	11.9
WECC	0.5	2.1	14.1	0.3	2.1	14.9	1.5	2.0	9.1
TRE	0.7	9.0	13.4	0.7	8.5	13.4	0.7	12.4	13.1
SPP	3.0	5.8	8.9	3.3	6.1	9.2	1.8	4.2	7.5
SERC	1.2	5.8	8.0	1.3	6.1	8.3	1.0	3.2	5.9
RFC	0.4	5.1	6.7	0.3	5.0	6.7	0.8	6.1	6.9
FRCC	0.1	10.4	5.0	0.1	10.8	5.2	0.5	7.8	3.3
Hawaii	0.0	1.6	2.1	0.0	1.6	2.2	0.1	1.6	1.8
ASCC	0.0	0.0	1.2	0.0	0.0	1.3	0.0	0.0	0.6
NPCC	0.1	0.3	0.7	0.1	0.3	0.6	0.8	1.0	1.1
United States	0.7	4.7	8.7	0.6	4.7	8.9	1.0	4.2	7.0

Table 3.2 provides estimated penetration rates of advanced meters by state. States with the highest growth are located primarily in the West, with Arizona, Oregon, and Idaho having advanced meter penetration rates above 25 percent. The increase in advanced metering penetration in Arizona is primarily due to movement by Arizona Public Service Company toward a planned target of more than 800,000 advanced meters over the next five years, as well as Salt River Project's reported 450,000 advanced meters, with a goal of one million by 2013.[7] In Oregon, Portland General Electric is moving forward with its plan to have over 850,000 customers on advanced meters by the end of 2010. Idaho Power projects 450,000 advanced meters by 2011. Pennsylvania and Wisconsin have penetrations above 20 percent. Wisconsin has the highest penetration in the MRO region. Pennsylvania has the highest penetration in RFC, mostly because of large numbers of advanced meters already reported in the 2008 FERC Survey. Missouri and South Carolina, both in SERC, also report robust growth in penetration.

[7] Salt River Project, 2010 Annual Report, available at http://www.srpnet.com/about/financial/2010annualreport/power.aspx.

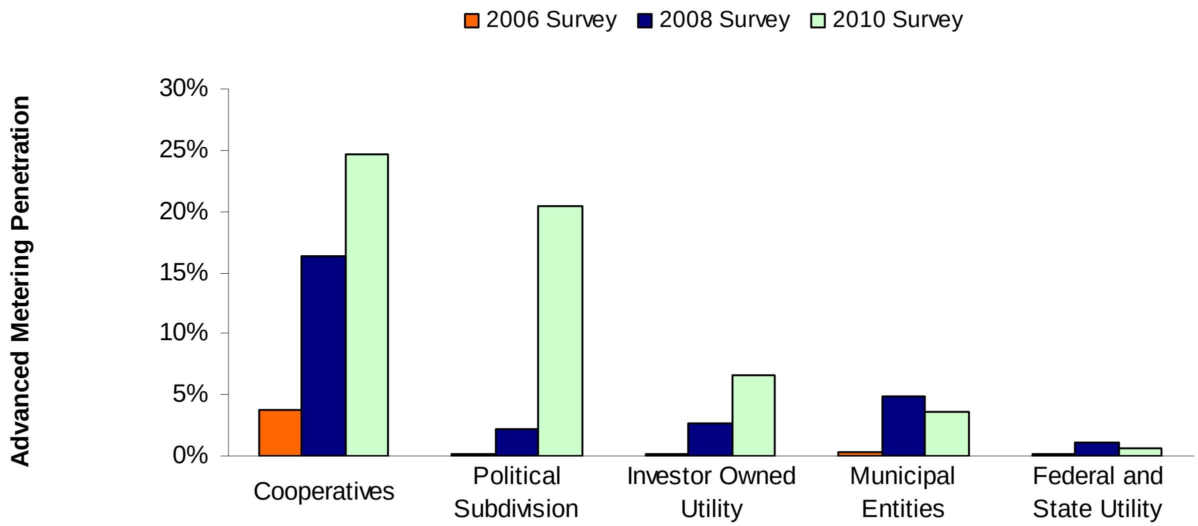
Table 3.2. Estimated penetration of advanced metering by state in 2006, 2008 and 2010 FERC Surveys

	2006			2008			2010		
State	AMI meters	Total meters	Penetration	AMI meters	Total meters	Penetration	AMI meters	Total meters	Penetration
AZ	5,521	2,783,083	0.2%	96,727	2,810,224	3.4%	847,177	2,915,712	29.1%
OR	2,960	1,821,710	0.2%	39,797	1,890,423	2.1%	478,897	1,896,717	25.2%
ID	29,062	739,199	3.9%	105,933	769,963	13.8%	198,370	803,576	24.7%
PA	18,200	6,053,110	0.3%	1,443,285	6,036,064	23.9%	1,493,201	6,152,994	24.3%
WI	19,882	2,983,075	0.7%	117,577	3,039,830	3.9%	757,688	3,418,498	22.2%
CA	40,153	14,253,873	0.3%	170,896	14,595,958	1.2%	2,475,896	14,837,434	16.7%
MO	8,986	3,087,821	0.3%	204,498	3,098,055	6.6%	506,416	3,072,893	16.5%
SC	19,655	2,007,339	1.0%	114,619	2,373,047	4.8%	312,894	2,445,044	12.8%
GA	73,312	4,404,447	1.7%	342,772	4,537,717	7.6%	514,403	4,401,623	11.7%
TX	28,200	10,195,134	0.3%	868,204	10,870,895	8.0%	1,284,179	11,013,153	11.7%
KY	27,501	2,225,485	1.2%	105,460	2,161,142	4.9%	273,663	2,523,833	10.8%
OK	60,273	2,024,592	3.0%	161,795	1,875,325	8.6%	215,462	2,028,522	10.6%
ND	29	367,776	0.0%	33,336	375,473	8.9%	42,875	445,164	9.6%
SD	7	484,728	0.0%	41,191	475,477	8.7%	41,122	432,632	9.5%
TN	426	3,165,211	0.0%	60,385	3,160,551	1.9%	252,341	2,761,758	9.1%
VT	1	331,161	0.0%	20,755	375,202	5.5%	31,293	379,139	8.3%
NC	29,411	4,681,178	0.6%	143,093	4,771,479	3.0%	385,884	4,847,336	8.0%
MS	82	1,015,493	0.0%	3	1,454,275	0.0%	97,344	1,511,958	6.4%
MI	31,254	4,877,345	0.6%	73,948	5,311,570	1.4%	269,933	4,865,396	5.5%
NM	1	875,393	0.0%	20,776	904,861	2.3%	54,250	1,015,058	5.3%
AL	89,702	2,738,519	3.3%	139,972	2,774,764	5.0%	127,092	2,467,741	5.2%
FL	8,479	9,679,565	0.1%	765,406	9,591,363	8.0%	490,150	9,644,617	5.1%
VA	5,016	3,412,011	0.1%	6,448	3,965,584	0.2%	175478	3,663,525	4.8%
WY	0	272,033	0.0%	12,268	318,282	3.9%	14,437	303,272	4.8%
MT	162	529,135	0.0%	8,979	549,136	1.6%	27,470	577,745	4.8%
IL	43,043	5,510,470	0.8%	112,410	5,701,533	2.0%	286,568	6,099,158	4.7%
CO	39,274	2,263,873	1.7%	39,873	2,246,184	1.8%	111,330	2,403,001	4.6%
OH	1,958	6,307,050	0.0%	28,042	5,544,353	0.5%	289,970	6,290,618	4.6%
IN	13,137	3,217,359	0.4%	61,551	3,115,205	2.0%	148,129	3,355,485	4.4%
KS	18,913	1,430,953	1.3%	61,423	1,426,832	4.3%	62,626	1,467,092	4.3%
MN	11,780	2,537,414	0.5%	37,071	2,542,113	1.5%	108,232	2,602,360	4.2%
WA	477	3,061,233	0.0%	69,377	2,987,355	2.3%	128,857	3,298,781	3.9%
IA	110	1,591,985	0.0%	46,407	1,714,774	2.7%	58,092	1,576,475	3.7%
ME	716	773,164	0.1%	426	780,748	0.1%	20,315	796,691	2.5%
LA	44	1,037,355	0.0%	44,103	2,186,249	2.0%	53,848	2,245,066	2.4%
DE	16	421,331	0.0%	0	438,020	0.0%	10,433	455,926	2.3%
HI	45	465,314	0.0%	6,550	405,228	1.6%	8,713	411,232	2.1%
NV	17	1,193,873	0.0%	10,835	1,292,331	0.8%	24,378	1,255,950	1.9%
NE	1,520	937,148	0.2%	8,630	970,774	0.9%	19,290	999,353	1.9%
UT	1	1,036,605	0.0%	37	1,056,718	0.0%	20,046	1,083,069	1.9%
AK	6	305,949	0.0%	18	315,419	0.0%	3,835	316,289	1.2%
AR	75,118	1,494,383	5.0%	168,466	1,488,124	11.3%	14,578	1,529,065	1.0%
WV	17	1,234,035	0.0%	10	1,183,513	0.0%	7,039	1,033,802	0.7%
MA	6,940	3,244,778	0.2%	3,907	3,077,679	0.1%	20,831	3,150,098	0.7%
NJ	25,222	3,884,140	0.6%	9,866	3,900,716	0.3%	25,744	3,953,683	0.7%
RI	398	480,275	0.1%	148	480,135	0.0%	2,381	506,379	0.5%
NY	3,071	7,906,309	0.0%	12,778	7,811,335	0.2%	28,664	9,313,776	0.3%
MD	130	1,972,886	0.0%	8	1,938,948	0.0%	4,189	2,483,628	0.2%
CT	3,862	1,580,365	0.2%	5,838	1,600,768	0.4%	1,967	1,625,758	0.1%
NH	306	759,514	0.0%	260	763,683	0.0%	391	755,770	0.1%
DC	0	809,412	0.0%	1,348	809,412	0.2%	2	275,554	0.0%

*Florida and Arkansas show a large apparent decrease in advanced meter count as a result of the 2010 FERC Survey's more restrictive definition of advanced meters. The District of Columbia shows a large apparent decrease in total meter count due to a correction in the 2010 FERC Survey result of reporting issues in the 2008 FERC Survey results that erroneously included meters in the Maryland suburbs.

Figure 3.3 provides estimated penetration rates by type of entity. Political subdivisions[8] have the fastest growth in advanced metering penetration, from 0.1 percent in the 2006 FERC Survey to 20 percent in the 2010 FERC Survey. The high advanced meter penetration in Cooperatives continues the trend seen in the 2006 and 2008 FERC Surveys. The decline in advanced meter penetration for municipal entities from 2008 to 2010 is the result of the change to the definition of advanced meters as discussed in the Definition of Advanced Metering section above.

Figure 3.3. Estimated penetration of advanced metering by type of entity in 2006, 2008 and 2010 FERC Surveys



	Cooperatives	Political Subdivision	Investor Owned Utility	Municipal Entities	Federal and State Utility
2006 Survey	3.8%	0.1%	0.2%	0.3%	0.2%
2008 Survey	16.4%	2.2%	2.7%	4.9%	1.1%
2010 Survey	24.7%	20.3%	6.6%	3.6%	0.7%

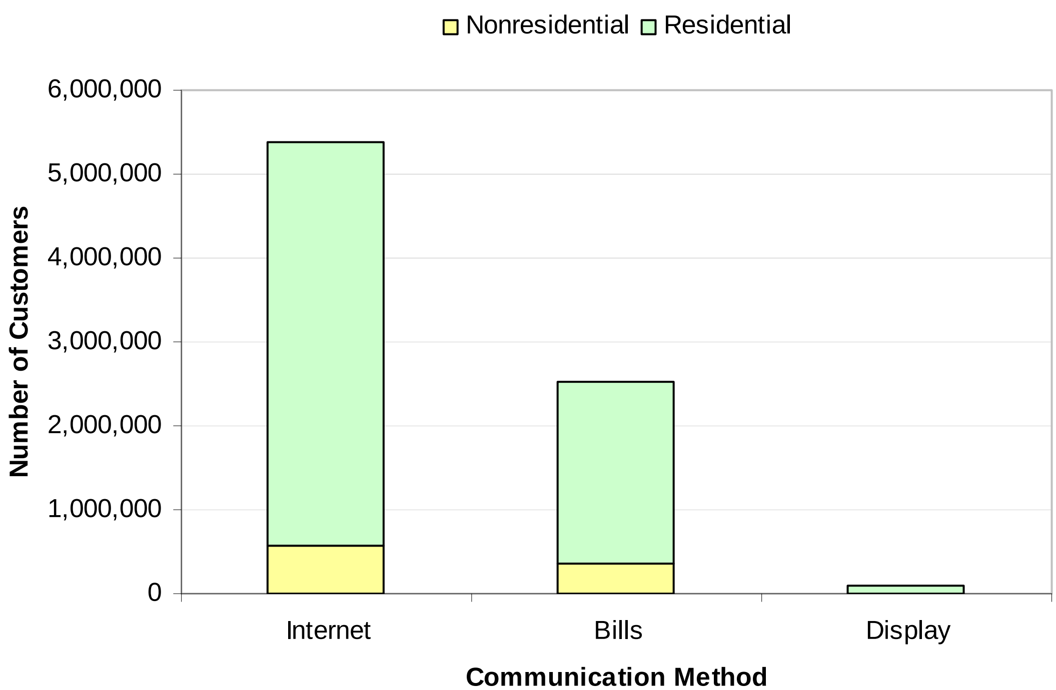
Type of Entity

[8] Respondents identifying themselves as political subdivisions in the 2010 FERC Survey include public power districts, public utility districts, water and power agencies and authorities, and irrigation districts.

Uses of Advanced Metering

The 2010 FERC Survey asked respondents to categorize their Demand Response and Time-based Rates/Tariffs (DR/TBR) customers by the ways in which they are capable of receiving data on their electricity use: over the internet, on their bills or invoices, or via a display unit. The responses categorize about 8 million customers—about 5.5 percent of all meters in the U.S. Figure 3.4 presents the results. Use of the internet predominates for residential and nonresidential customers, with bills and invoices making up almost all of the remainder.[9] Display units are very uncommon.

Figure 3.4. Reported numbers of customers and communication methods for advanced metering by customer class



[9] Information may be delivered by more than one method. For example, customers may view frequently updated information online and also receive a monthly bill. For other types of customers, such as transportation and agriculture, bills and invoices are the more common data channel and the internet is slightly less prevalent.

Developments and Issues in Advanced Metering

There have been several developments in advanced metering since the Commission issued its last report including the Department of Energy's (DOE) completion of awards supporting Advanced Metering Infrastructure (AMI) deployment and demonstration projects, work on proposed standards under the National Institute of Standards and Technology (NIST) process, DOE reports on smart grid communications issues, expanded data collection efforts, noteworthy actions by state regulatory agencies, and technological advancements. This section of the report highlights these developments and describes some of the challenges facing AMI.

American Recovery and Reinvestment Act Grant Programs

The Department of Energy completed awards for 31 AMI grants worth $817 million under the American Recovery and Reinvestment Act (ARRA) Smart Grid Investment Grant Program.[10] The ARRA grants allow recipients to recover up to 50 percent of the eligible project costs and are designed to accelerate the commercial use and implementation of AMI technologies. The ARRA AMI grants support projects with a total value of $2 billion in 29 states. The projects are focused on providing AMI to retail consumers and, in some cases, information and pricing mechanisms that will allow consumers to reduce their energy use and costs, and improve the reliability of systems.

The DOE also awarded $2.1 billion of funding under the ARRA Integrated and/or Crosscutting Systems Grant Program to support 39 demonstration projects that focus on adding intelligence and integrating smart grid and AMI capabilities in specific utility transmission and distribution systems throughout the United States. These system-based projects are valued in excess of $4.9 billion and are located in 31 jurisdictions. The projects include activities such as installing open, interoperable, two-way communications networks, deploying smart meters for customers, developing demand response and price responsive demand programs, automating advanced distribution and transmission applications, developing "self-healing" and power restoring properties on the grid, developing improved pricing programs, and supporting the deployment of plug-in electric vehicles.

In addition, the DOE awarded grants supporting 16 regional demonstration projects that include smart meters in nine states. These large demonstration projects are designed to provide industry with business models, data to assess technical capabilities, and actual cost and benefit information associated with integrating these systems and components on a network level.

[10] Additional information pertaining to the grants and projects is accessible via the Federal Smart Grid Task Force, SmartGrid.gov – ARRA Smart Grid Programs, available: http://www.smartgrid.gov/projects.

Federal Government-Led Activities to Support AMI Structures and Utilization

Federal agencies and their stakeholder groups are conducting a number of activities designed to establish standards and protocols, develop common frameworks for access and data security, and collect timely information to support common structures and improve utilization of AMI.

The National Institute of Standards and Technology Smart Grid Interoperability Standards

The Energy Independence and Security Act (EISA) of 2007 gave the National Institute of Standards and Technology (NIST) "primary responsibility to coordinate development of a framework that includes protocols and model standards for information management to achieve interoperability of smart grid devices and systems…." NIST issued its *NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 1.0* in January 2010. In this document NIST reports that the smart grid will "ultimately require hundreds of standards, specifications, and requirements." It also identified eight priority areas for standards development, including AMI standards.[11]

NIST reviewed reports and other relevant literature and consulted with standards development organizations and smart grid stakeholders to identify gaps in current standards. NIST launched a public-private partnership, the Smart Grid Interoperability Panel (SGIP), to assist NIST and support the ongoing evolution of smart grid standards. NIST and the SGIP have initiated priority action plans and have overseen the organization of associated working groups to address those gaps. Two of the priority action plans focus on issues associated with smart metering.

Priority action plan 05, Standard Meter Data Profiles, seeks to develop a common format for retrievable meter data to simplify client access to commonly shared information. Priority action plan 06, Demonstrate Common Semantic Model Translations for End Device Data, seeks to develop a common form to which meter information may be translated to (1) facilitate communication between devices and (2) support the common and accurate translation of information between meters and other devices.

The Cyber Security Working Group (CSWG) is a permanent working group of the SGIP that focuses on cyber security aspects of the smart grid framework. In September 2010, NIST released the *NIST Interagency Report 7628: Guidelines for Smart Grid Cyber Security* stemming from the work of the CSWG. One volume of the report focuses on privacy issues;[12] NIST concluded with respect to privacy that the challenges associated with

[11] National Institute of Standards and Technology, Office of the National Coordinator for Smart Grid Interoperability, *NIST Framework and Roadmap for Smart Grid Interoperability Standards*, Release 1.0, NIST Special Publication 1108, January 2010, p. 10 Available: http://www.nist.gov/public_affairs/releases/upload/smartgrid_interoperability_final.pdf.

[12] NIST, "Guidelines for Smart Grid Cyber Security: Vol. 2, Privacy and the Smart Grid," NISTIR 7628, August 2010, p. 1, Available: http://csrc.nist.gov/publications/nistir/ir7628/nistir-7628_vol2.pdf.

safeguarding the new types of information transmitted and collected by smart grid devices have not been tested, and it is unclear if existing laws and regulation mitigate the associated risks. NIST found that the existing business policies and practices of utilities and third-party smart grid providers may not adequately address the privacy risks created by smart meters and smart appliances.

NIST recommends that stakeholders follow standard privacy and information security practices to effectively and consistently safeguard the privacy of personal information. These practices may include conducting a privacy impact assessment before making the decision to deploy smart grid technologies. In addition, NIST recommends that stakeholders develop and document privacy policies and practices drawn from the Organization for Economic Cooperation and Development's Privacy Principles and other authorities. NIST also recommends that stakeholders engage in privacy training and consumer education about privacy risks and mitigation actions. Additionally, NIST recommends that smart meters and other types of smart devices should be engineered to collect only the data necessary to allow the device to function for the purposes agreed to by smart grid consumers.

The CSWG is also analyzing AMI cybersecurity challenges with regard to authentication of users and data, secure communications, and valid firmware updates. These challenges stem in part from a variety of AMI system attributes including the large number of meters which could represent points of access for a threat, typically limited processing capability within the meter that may be insufficient for complex security algorithms, and a network design that relies on information transfer from meter to meter before the accumulated data is relayed to the utility back office.[13]

Department of Energy Reports Concerning Use and Security of AMI Information

The DOE released two reports on October 5, 2010 that describe findings from its investigation of fundamental consumer and technology issues associated with AMI. DOE's report, *Communication Requirements of Smart Grid Technologies*, finds that realization of smart grid benefits will rely on the increased use of communications and information technology and that sufficient access to communications facilities is critically important. The report states that DOE will seek to work with the Federal Communications Commission and the National Telecommunications and Information Administration to review possibilities for spectrum access to accommodate smart grid needs, and will need input from the utility and communications industries to determine spectrum requirements and identify additional and potentially available spectrum to support smart grid wireless communications needs. Devices that may require wireless technology include AMI. The report recommended the development of an online, interactive clearinghouse for smart grid communications technology applications, that would serve as a resource for utilities to share lessons learned in the smart grid context. In addition, the clearinghouse could include substantive information about the technologies and information on existing federal programs that may be helpful to utilities and their suppliers as they implement smart grid technologies.

[13] *Id.* at 31.

The second report, *Data Access and Privacy Issues Related to Smart Grid Technologies*, provides: (1) DOE's findings based on information received through an agency request for information to the public, and (2) a comprehensive summary of public comments on the issues from the spring and summer 2010 proceeding on data-privacy and data-security issues. DOE found that the residential and commercial customers should have access to their own detailed energy consumption information and that the information should be accorded privacy protections, including a prohibition of disclosure to third parties unless specifically authorized by the customer. If a customer grants a third party access to the energy data, that third party should also be required to protect the privacy and security of the information. DOE also found that consumer education and flexibility in technology and pace of deployment will be critical to the success and consumer acceptance of smart grid technologies.

Energy Information Administration Data Collection Efforts

EIA will significantly expand its collection of AMI-related data collection beginning in 2011 to improve the breadth and timeliness of its information on AMI. EIA revised its Form EIA-826, "Monthly Electric Sales and Revenue with State Distributions Report" to collect monthly, by state and sector, the number of Advanced Meter Reading (AMR) and AMI meters installed, as well as the energy served through AMI meters. These revisions may improve the ability of interested parties to monitor and assess AMI deployment and utilization in the United States.

Noteworthy State Activities

A key issue that states have been addressing is the method by which utilities may recover their investments in AMI. Utilities normally seek recovery of costs associated with infrastructure investments through rate cases held before state regulatory agencies. These rate cases generally address a wide variety of costs and can be time consuming and costly for all parties involved. In addition to rate case treatment, some states have approved a variety of funding mechanisms to support AMI, including cost trackers and surcharges.

In general, cost trackers and surcharges provide cost recovery close to when the expenses associated with investments are incurred. Cost trackers typically allow for dollar-for-dollar cost recovery by the utility as costs are incurred. Surcharges (sometimes also called rate riders) recover costs by increasing rates by a set amount for a specific period of time. Surcharges generally reconcile cost estimates with actual costs on a quarterly or annual basis, which may slightly delay cost recovery.

The use of these alternative cost recovery mechanisms generally include prudence reviews by state regulatory agencies. While these reviews may be limited in scope, they can help to achieve balance between ratepayers and investors. In August 2010, the Maryland Public Service Commission deferred recovery of the costs Baltimore Gas and Electric Company incurred to install AMI until the company is able to show in a future rate case that the meter installation is successful and cost-effective for consumers. It also conditioned the cost recovery on the inclusion of a mechanism under which shareholders bear a portion of the financial risk.[14]

Some states grant approval to pilot projects and full-scale deployment of smart meters, choosing the cost recovery mechanism each believes is appropriate. For example, the Corporation Commission of Oklahoma granted approval in July 2010 to the Oklahoma Gas & Electric Company for surcharge recovery of full-scale deployment smart meters in the company's service territory.[15] In October 2010, the New York Public Service Commission approved a surcharge for Consolidated Edison Company's smart grid demonstration project and deferred cost recovery of five other utility projects funded through ARRA for consideration in future rate cases.[16] At least one state identified situations where alternative cost recovery mechanisms are not appropriate. In September 2010, the 2nd Appellate Court of Illinois issued a decision prohibiting the use of a surcharge or rider to fund AMI investments associated with a pilot program initiated in 2009 by the Commonwealth Edison Company.[17]

States are also addressing the consumer privacy issues associated with AMI. In September 2010, California enacted legislation to ensure privacy protection for consumers and their energy consumption data.[18] The legislation provides parameters by which an authorized third party can access and share a customers' electric usage information and requires customer consent for release of its energy information. Subsequent to the legislation, the California Public Utilities Commission held a workshop on October 25 and 26, 2010 to address issues related to the creation of rules to allow for an authorized third party to access a customers' electric usage information and consider any associated privacy protections that should be implemented.[19]

States have also been actively addressing customer complaints and are finding that a common element in many challenges facing AMI is the need for consumer education, as identified in the National Acton Plan on Demand Response. Consumer education could

[14] Maryland Public Service Commission, Case No. 9208: In the Matter of the Application of Baltimore Gas and Electric Company for Authorization to Deploy a Smart Grid Initiative and to Establish a Surcharge for the Recovery of Cost, Order No. 83410 and Order No. 83531.

[15] The Corporation Commission of Oklahoma, Cause No. PUD 201000029: In the Matter of the Application of Oklahoma Gas and Electric Company for an order of the Commission Granting Pre-approval of Deployment of Smart Grid Technology in Oklahoma and Authorization of a Recovery Rider and Regulatory Asset, Order No. 576595, Available: http://www.occeweb.com/SmartMeter/Final%20Order%20Approving%20Joint%20Stipulation%20and%20Settlement%20Agreement.pdf.

[16] New York Public Service Commission, Case 09-E-0310: In the Matter of the American Recovery and Reinvestment Act of 2009 - Utility Filings for New York Economic Stimulus, Order Issued and Effective October 19, 2010, Available: http://documents.dps.state.ny.us/public/Common/ViewDoc.aspx?DocRefId={938D8D3D-25EE-4C25-BCD3-A849B330E260}.

[17] Commonwealth Edison Co. v. Ill. Commerce Comm'n, Nos. 2-08-0959, 2-08-1037, 2-08-1137, 1-08-3008, 1-08-3030, 1-08-3054, 1-08-3313 cons., 2010 Ill. App. LEXIS 1057, (App. Ct. Ill., 2d Dist. Sept. 39, 2010), pet. for appeal denied, 2010 Ill. LEXIS 1312, p. 41.

[18] California Legislative Counsel, Senate Bill 1476 of the 2009-2010 Session, Available: http://www.leginfo.ca.gov/pub/09-10/bill/sen/sb_1451-1500/sb_1476_bill_20100929_chaptered.pdf.

[19] CPUC, California's Smart Grid, Available: http://www.cpuc.ca.gov/PUC/energy/smartgrid.htm.

speed adoption of programs that employ AMI to empower and benefit consumers. For example, providing appropriate education early in an advanced meter deployment could alleviate some concerns that typically arise during deployment, such as those experienced in California and Texas where customers initially believed that the new meters were not accurate and later learned—through an independent evaluation of the accuracy and reliability of the installed AMI—that the advanced meters, software and billing systems may be more accurate than the old meters. [20] [21]

Technological Issues in Advanced Meters

Recent technological improvements have expanded capabilities and reduced costs for advanced meters. An important advancement is the migration to full solid state advanced meters. Their use replaced the practice of combining separate communications components with measurement electronics[22] or, for early advanced meters, the retrofitting of electromechanical meters with electronic modules containing communications and intelligence.

These developments have led to a more unified platform, consolidation of common functions, and improvements in communications technologies. Greater use of application-specific integrated circuits and more capable microprocessors lower the cost of a system while reducing space requirements and providing greater functional capability including remote reprogramming. The design of smart meters now generally includes functional upgradability that was not possible with earlier units. These advancements have greatly improved the ability of advanced meters to support the growing utility requirements for demand response capability, tariff management, reliability management, and other programs to empower the consumer.

Component interoperability, the ability of diverse systems to work together, also becomes more important as the interaction of power system components increase. Early adopters of AMI face interoperability issues as technology and standards evolve. Recently, utilities that installed meters that include integrated home area network (HAN) components have raised concerns that their meters may become obsolete if the industry adopts communication protocols for appliances and other components that are incompatible with their meters. The HAN's function is to interconnect in-home devices, such as thermostats and appliances, and provide a bridge for communication to the power grid. While it is unclear how many meters this issue currently affects, it could be significant in the future as at least one firm projects that HAN capabilities will be included in 81% of all smart meters in North America by

[20] Structure Consulting Group, LLC., "PG&E Advanced Metering Assessment Report," Commissioned by the California Public Utilities Commission, A.07-12-009 COM/MP1/jt2, pp. 8-9, Available: http://www.cpuc.ca.gov/NR/rdonlyres/2B0BA24E-E601-4739-AC8D-DA9216591913/0/StructureExecutiveSummary.pdf.

[21] Navigant Consulting, "Evaluation of Advanced Metering System (AMS) Deployment in Texas – Meter Accuracy Assessment," July 30, 2010, p. 11, Available: http://www.puc.state.tx.us/electric/reports/ams/PUCT-Final-Report_073010.pdf.

[22] The meter industry uses the term metrology, which includes a broad range of measured quantities including billing register data (e.g., consumption and demand) and interval usage data.

2013.[23] Stakeholders are engaged in a number of processes to resolve this issue, including the development of protocol agnostic modular devices that could serve as communication bridges from the in-home devices to either the HAN or power grid.

The importance of the interoperability challenge is illustrated by the 2009 implementation of a company-wide AMI system by a Western utility. The utility found that the meters and the other system components selected for the AMI project did not properly function together. The utility ceased its AMI project as a result of this lack of interoperability and filed a request with the state regulator to conduct a new and extended AMI pilot project through 2011. The regulator denied the request and noted that any subsequent application should include or be preceded by an overall smart grid plan.

[23] Pike Research new release: "49% of Smart Meters to Include Home Area Networking Connectivity by 2013", April 23, 2010 (http://www.pikeresearch.com/newsroom/49-of-smart-meters-to-include-home-area-networking-connectivity-by-2013).

CHAPTER 3. DEMAND RESPONSE

This chapter addresses the second and third topics in EPAct 2005 section 1252(e)(3):

(B) Existing demand response programs and time-based rate programs, and
(C) The annual resource contribution of demand resources.

In this chapter, Commission staff present results of the 2010 FERC Survey on demand response programs, comparisons to the 2006 and 2008 FERC Survey results, and the number of entities offering demand response programs, enrollment levels, and peak load reductions for these programs by entity type and by region.

The information in the chapter provides summary-level results of demand response program activity and resources. Detailed information on responses is available on FERC's website, http://www.ferc.gov/industries/electric/indus-act/demand-response/dem-res-adv-metering.asp.

This chapter has three sections:

- Definition of Demand Response
- Survey Results
- Demand Response Activities at the FERC, Barriers to Demand Response, and Staff Recommendations

Definition of Demand Response

The definition of demand response used in this survey and report is:

> **Demand Response**: Changes in electric use by demand-side resources from their normal consumption patterns in response to changes in the price of electricity, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.

This definition substitutes "demand-side resources" for the phrase "end-use customers" used in previous surveys, to conform to the definition in use by NERC's Demand Response Data Task Force in its development of a Demand Response Availability Data System (DADS) to collect demand response program information. Commission staff also modified the 2006 and 2008 FERC Survey instruments for the 2010 FERC Survey. The number of program classifications was expanded from twelve in 2008 to fifteen in 2010. For some program classifications the 2008 definitions were altered.[24] The new types and definitions also

[24] The changes in number and definition of program types may have caused respondents to reclassify programs from the 2008 FERC Survey to be consistent with the 2010 FERC Survey. Unlike the 2008 FERC Survey,

conform to NERC's DADS. Common terminology will allow comparison with the DADS data. Table 4.1 contains the program classifications of the 2010 FERC Survey instrument. A definition for each is in Appendix C, Glossary.

Table 4.1. Demand response program classifications in the 2010 FERC Survey and changes from previous surveys

2010 FERC Survey Program Classifications	Change from Previous FERC Surveys
Direct Load Control	
Interruptible Load	
Critical Peak Pricing with Control	New program classification
Load as Capacity Resource	
Spinning Reserves	Previously included in Ancillary Services classification
Non-Spinning Reserves	Previously included in Ancillary Services classification
Emergency Demand Response	
Regulation Service	Previously included in Ancillary Services classification
Demand Bidding and Buyback	
Time-of-Use Pricing	
Critical Peak Pricing	
Real-Time Pricing	
Peak Time Rebate	
System Peak Response Transmission Tariff	New program classification
Other	

Survey Results

Analysis Approach

As in the advanced metering chapter of this report, this demand response section includes figures and tables of reported results from survey respondents, as well as estimated information for the entire survey population including the nonresponding entities. The estimated values of demand response program information for nonrespondents were based on data from the 2008 EIA-861[25] and the 2008 FERC Demand Response Survey. **Appendices D and H** provide a detailed explanation of the analysis and estimation approach.

In this chapter also, figures and tables with results compiled directly from data submitted by survey respondents without estimation of results for those not reporting are labeled "Reported" or "Reporting." Figures and tables with results that include both data submitted

where respondents could choose multiple program classifications for a single program, the 2010 Survey forced the selection of a single program classification for each program reported.

[25] U.S. Energy Information Administration, *Form EIA-861 Final Data File, available at http://www.eia.doe.gov/cneaf/electricity/page/eia861.html.*

by survey respondents and estimation of results for those not reporting, based on survey and other information, are labeled "Estimated."

The diversity of demand response programs poses a survey and reporting challenge. For instance, the same demand response potential may be reported by a utility and also by an RTO in whose program the utility participates. To avoid double-counting, the analysis subtracts the utility potential from the RTO's potential, but this may not be possible if the utility and the RTO assign the program to different categories. FERC staff conferred with the RTOs, ISOs and a number of respondents, and sometimes changed their program categories to reduce any double-counting. Appendix D contains a cross-tabulation of RTO demand response programs in effect in 2009 and the program type assigned by staff to each RTO program. Double-counting can also occur with affiliates, and with generation and transmission cooperatives that supply energy to other cooperatives; staff attempted to identify and eliminate those errors as well. The rapid evolution of demand response programs, rules, and names increases confusion among respondents and staff alike and may have caused errors in spite of these measures.

The 2010 FERC Survey changed the way respondents classify demand response programs. In past surveys, respondents could assign multiple classifications to a single demand response program. In the 2010 FERC Survey, respondents were forced to choose a single classification. This change may have contributed to the decline in the number of reported demand response programs from 2,314 in the 2008 FERC Survey to 1,931 in the 2010 FERC Survey. The reported numbers of entities offering various programs and the reported numbers of customers enrolled in such programs may also have been affected. Comparisons between past and current survey results should be made with this change in mind.

Summary of Survey Findings

Entities with demand response programs; numbers of customers in demand response programs. Direct load control programs have been one of the most common demand response programs offered since 1968.[26] Direct load control programs are most often offered to residential or small commercial customers to control appliances such as air conditioning, water heating and pool pumps. These programs help sponsors balance load by remotely controlling the appliances during peak periods.

RFC, WECC, FRCC, MRO and SERC have active direct load control programs. Enrollment levels are relatively consistent with levels reported in the 2008 FERC Survey, except in WECC where enrollment in direct load control programs more than doubled from the 2008 FERC Survey, reaching 1.6 million customers. A contributing factor to the increase in direct load control enrollment in WECC may be the rollout over the past two years of direct load control programs by California's three investor-owned utilities (IOUs). The California IOUs are responding to a directive by the California Public Utilities Commission requiring them to offer direct load control programs in support of their business case for implementing

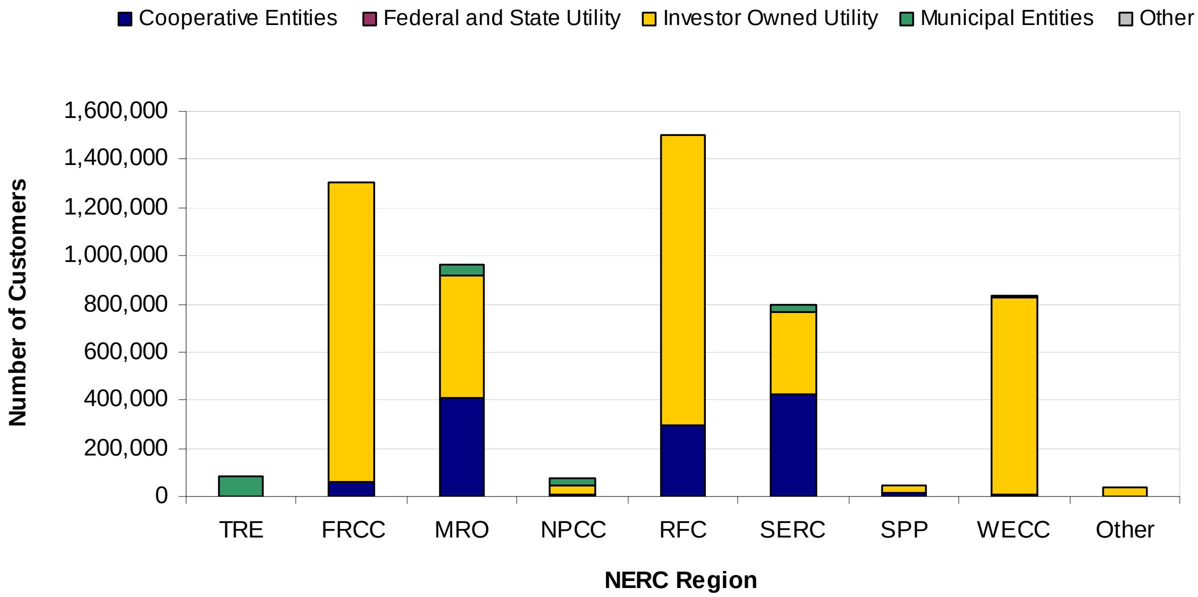
[26] According to the EPRI, Detroit Edison was the first utility to implement a load control program in 1968. EPRI, The Demand-Side Management Information Directory, EPRI EM-4326, 1985.

advanced meters. In contrast, the TRE, NPCC and SPP regions each have fewer than 150,000 customers enrolled in direct load control programs.

Consistent with the 2008 FERC Survey results, the 2010 results indicate the majority of customers enrolled in a direct load control program are in programs offered by their IOU, reflecting the larger number of customers in IOUs. This is true for all regions except TRE, where electric deregulation precluded regulated utilities from offering competitive services such as direct load control. After IOUs, cooperatives have the most customers enrolled in direct load control programs.

Figure 4.1 presents the reported number of customers enrolled in direct load control programs by region and entity type. It is noteworthy that over 10 percent of customers in MRO and FRCC regions participate in direct load control programs. In FRCC, Florida Power and Light's On Call direct load control program is the largest such program nationally, with over 800,000 customers enrolled.

Figure 4.1. Reported number of customers enrolled in direct load control programs by region and type of entity[27]

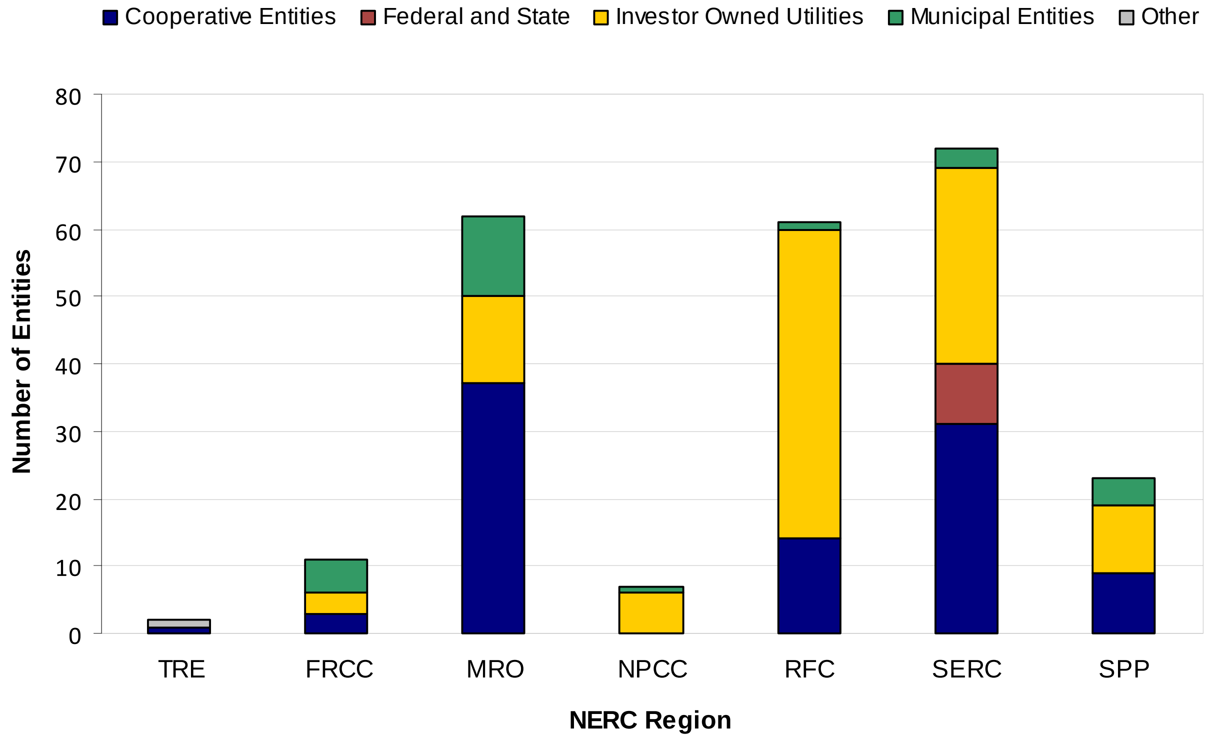


	TRE	FRCC	MRO	NPCC	RFC	SERC	SPP	WECC	Other
Percent of total estimated customers in the region in a direct load control program	0.8%	14.5%	12.5%	0.5%	4.1%	2.5%	0.7%	2.7%	5.7%

Figure 4.2 presents the number of entities reporting interruptible/curtailable rates by region and entity type. Like direct load control, interruptible/curtailable rates offer rate or tariff incentives. They differ from direct load control in that the customer, rather than the sponsor, curtails the load during peak times when directed. Nonresidential customers are typical participants in this type of program (residential customers are often ineligible to participate.)

[27] In this chapter, figures that report information for each entity type use the category "Cooperative Entities" for cooperatives, generation and transmission cooperatives, and political subdivisions. Similarly, municipal utilities and municipal marketing authorities are combined into "Municipal Entities." Federal entities, such as Southwestern Power Administration, and state utilities, such as the Arizona Power Authority, are combined into "Federal and State." Curtailment service providers, retail power marketers, regional transmission organizations and independent system operators are combined into "Other."

Figure 4.2. Number of entities reporting interruptible/curtailable rates by region and type of entity



The number of entities offering interruptible/curtailable rates rose from 248 in the 2008 FERC Survey to 265 in 2010 FERC Survey. More than 85 percent of the reporting entities are IOUs and Cooperatives. These programs are primarily in the MRO, RFC, and SERC regions. The SERC region has the highest number of entities reporting interruptible/curtailable rates: 72 entities, compared to 50 in 2008. MRO had the largest number of programs in 2008 (63) and has remained essentially unchanged in 2010. There is an increase in the number of interruptible/curtailment rates from 2008 to 2010 in all regions except NPCC. NPCC dropped from 30 in the 2008 FERC Survey to 7 in 2010.

Figure 4.3 presents the number of entities reporting time-of-use rates for residential customers by region and entity type. Time-of-use rates have prices that vary by time period, and the time periods are typically longer than one hour within a 24-hour day. The prices are known ahead of time and usually reflect the average cost of generating and delivering power during those time periods. Time-of-use rates are offered in every region by cooperatives, municipal and investor-owned utilities. MRO has the largest number of entities (46, the majority being municipals) reporting time-of-use rates. Sixty-nine fewer IOUs reported offering residential time-of-use rates in the 2010 FERC Survey than in the previous survey, contributing to an overall decline from 241 entities in the 2008 FERC Survey to 169 entities in the 2010 FERC Survey.[28]

[28] A methodology change in the 2010 Survey may have contributed to these declines. *See* discussion in the "Analysis Approach" section.

Figure 4.3. Number of entities reporting residential Time-of-Use rates by region and type of entity

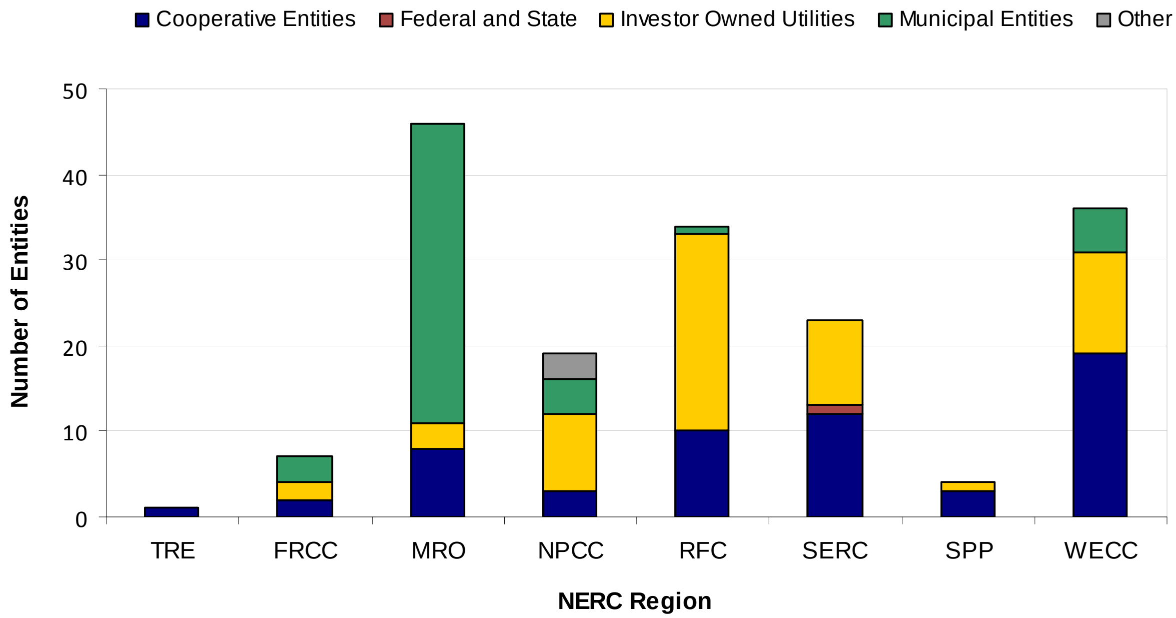


Figure 4.4 presents the reported number of residential customers enrolled in time-of-use rates by region and entity type. A reported 1.1 million U.S. residential customers are enrolled in time-of-use rates in the U.S. The number of residential customers reported on time-of-use rates declined from 1.28 million in the 2008 FERC Survey. IOUs have 77 percent of the reported time-of-use-enrolled customers. Cooperatives have the second highest percentage, about 22 percent of those enrolled. Despite time-of-use offerings by dozens of entities across the U.S., and particularly in MRO, most residential customers with time-of-use rates are in WECC.

Figure 4.4. Reported number of residential customers enrolled in Time-of-Use rates by region and entity type

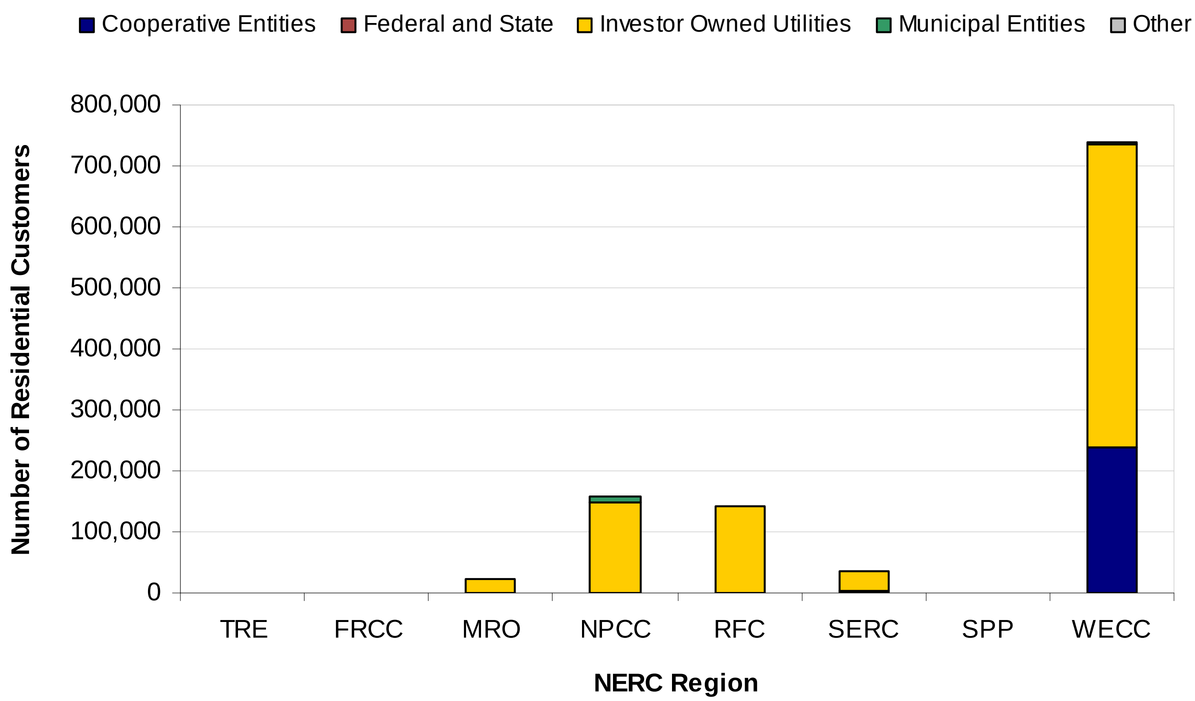
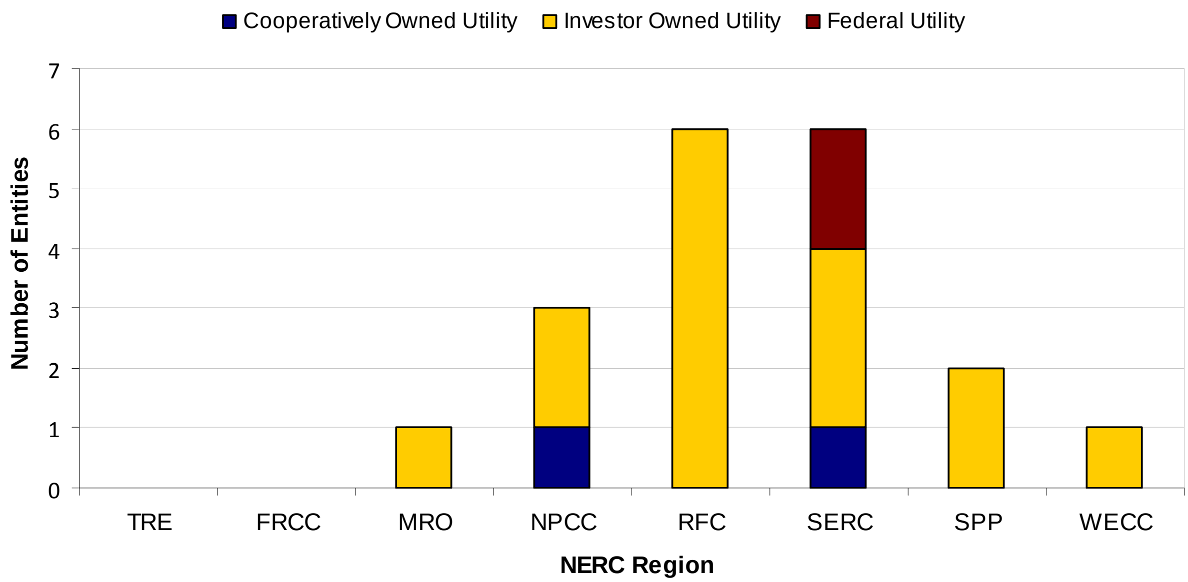


Figure 4.5 presents the number of entities reporting having a retail real-time pricing program by region and type of entity. Under real-time pricing, electricity prices vary hourly or more often to reflect changes in the wholesale price of electricity on a day-ahead or hour-ahead basis.

A total of 19 entities reported retail real-time pricing programs from all but two regions. This is down from the 85 entities reporting at least one real-time pricing program for retail customers in the 2008 FERC Survey. No municipal entities reported retail real-time pricing in the 2010 FERC Survey, although fifteen reported it in the 2008 FERC Survey. The number of cooperative entities with real-time pricing programs declined from 20 to two; IOUs with real-time pricing programs fell from 47 to fifteen.[29]

[29] A methodology change in the 2010 Survey may have contributed to these apparent declines. *See* discussion in the section "Analysis Approach". The IOU real-time pricing numbers reported in the 2008 Survey may have been inflated by the previous methodology: in February 2006, Barbose et al reported eleven IOUs had default real-time pricing rates and another fifteen were considering them (Killing Two Birds with One Stone: Can Real-Time Pricing Support Retail Competition and Demand Response?, LBNL-59739, August 2006).

Figure 4.5. Number of entities reporting retail real-time pricing by region and entity type



Reported potential peak load reduction. The total potential peak load reduction from demand response programs reported in the 2010 FERC Survey is 53,063 MW. This is up 42 percent from the 37,335 MW reported in the 2008 FERC Survey and 79 percent increase from the 29,653 MW reported in 2006. Figure 4.6 compares reported potential peak load reductions in the three FERC surveys.

Figure 4.6. Total reported potential peak load reduction in 2006, 2008 and 2010 FERC Surveys

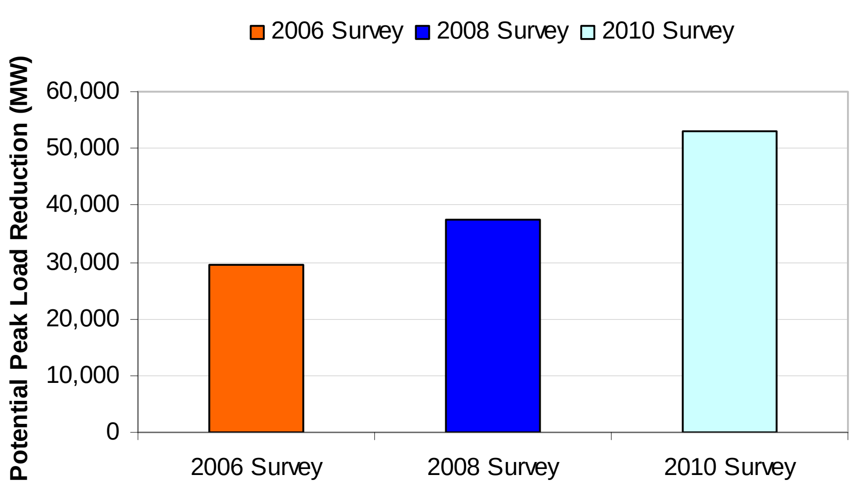


Figure 4.7 presents the reported potential peak load reduction by customer class across the three survey years. Wholesale market participants[30] and commercial and industrial customers together represent over 80 percent of the total potential peak reductions in the 2010 FERC Survey, as they did in the previous survey.

Wholesale market participants also had the largest increase in potential reductions: from 12,656 MW in the 2008 FERC Survey to 22,884 MW in the 2010 FERC Survey. Much of the increase in the wholesale class is due to the growth of demand response in RTOs, from a reported 9,060 MW in the 2008 FERC Survey to 20,533 MW in this survey (see Figure 4.13 below). Since 2007, ISO New England and PJM Interconnection have commenced long-term forward capacity markets that have attracted significant amounts of demand response.

Commercial and industrial customers' potential load reduction increased by 23 percent from the 2008 to 2010 FERC Surveys. Potential peak load reductions from residential customers remained relatively constant across all three survey periods.

[30] In this report, "wholesale market participants" refers to capacity reported in RTO demand response programs, less the demand response capacity reported by a retail utility and identified as also participating in an RTO demand response program. It also includes demand response capacity of wholesale entities such as generation and transmission cooperatives, municipal power agencies, and curtailment service providers.

Figure 4.7. Reported potential peak load reduction by customer class in 2006, 2008 and 2010 FERC Surveys

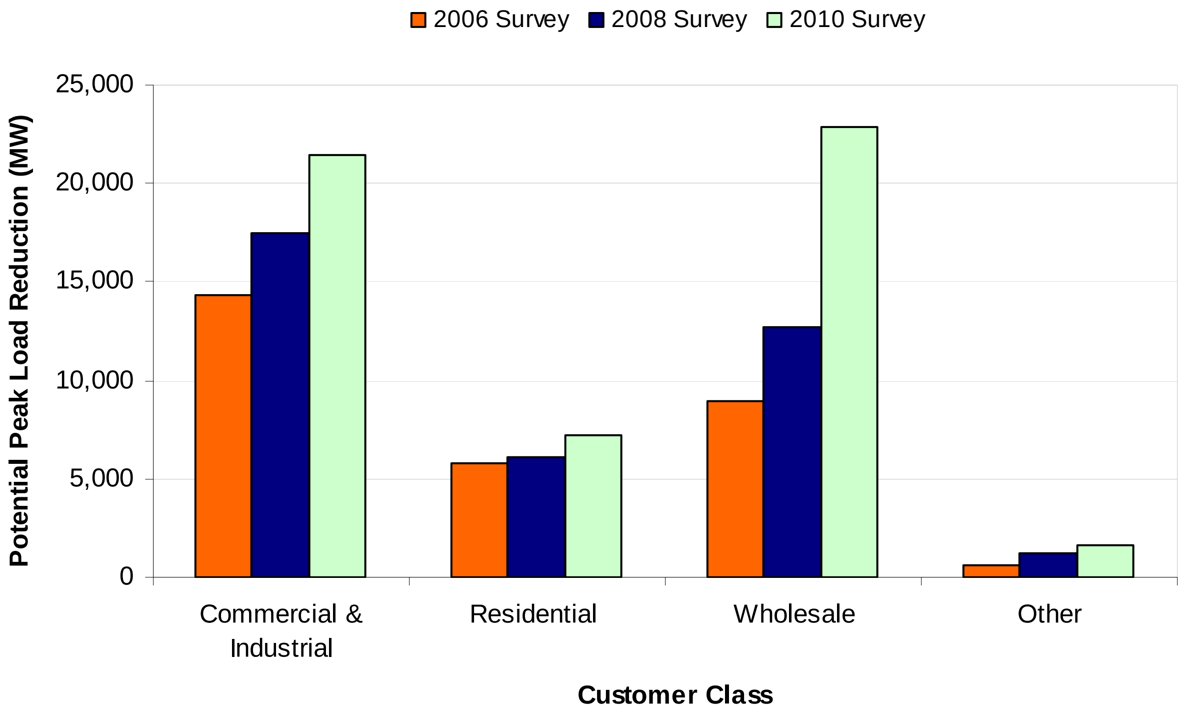


Figure 4.8 presents the 2010 FERC Survey results for reported potential peak load reductions by region and customer class. Potential peak load reductions in the RFC, MRO, and NPCC regions reflect the substantial wholesale demand response capacity of the RTOs in those regions. Commercial and industrial customers, though fewer in number than residential customers, provide a higher total level of load reduction potential than residential customers. Commercial and industrial customers are more likely to have systems and technology in place to facilitate demand response program participation. In addition, many demand response programs are available only to customers above a certain size cut-off.

Figure 4.8. Reported potential peak load reduction by region and customer class

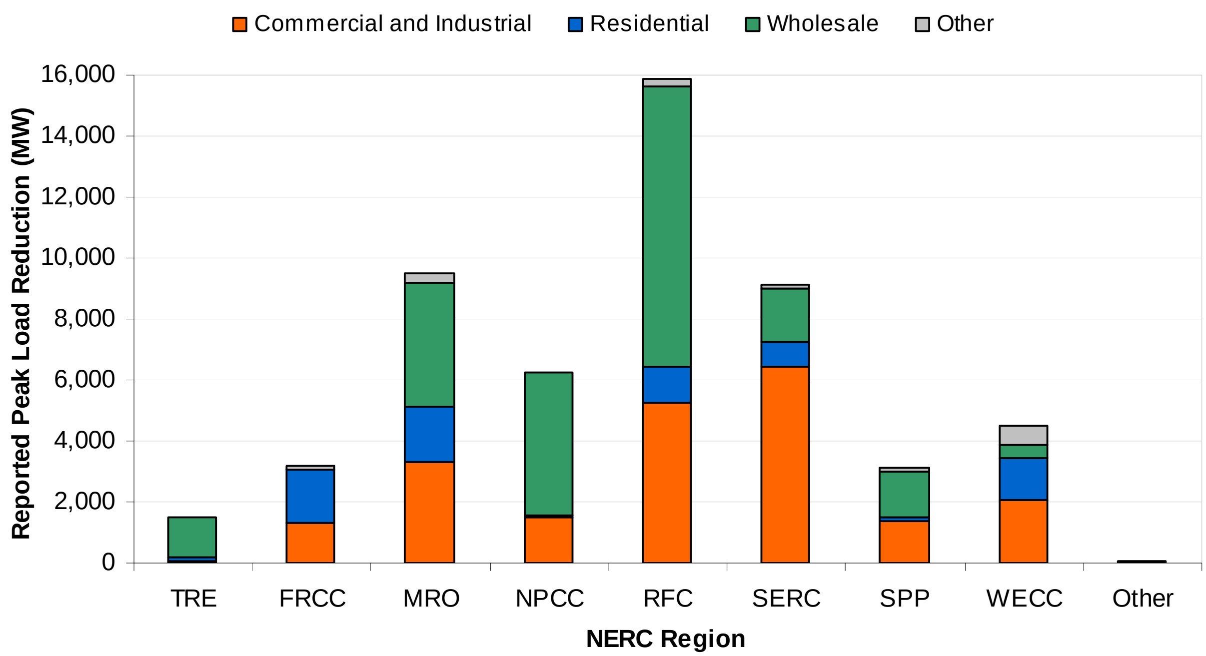
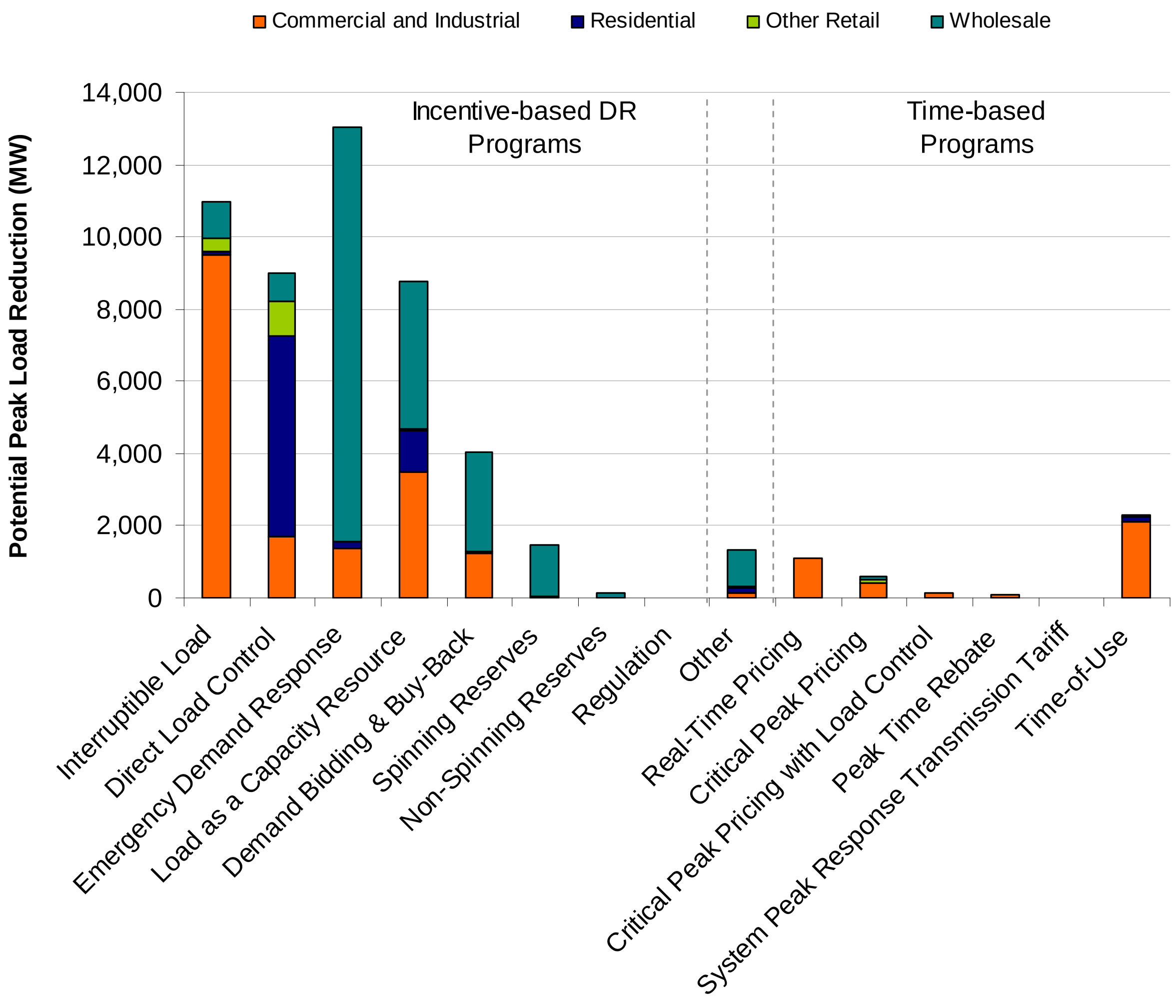


Figure 4.9 presents the reported potential peak load reduction by type of program and customer class. The top four demand response programs, Emergency Response, Interruptible Load, Direct Load Control, and Load as Capacity Resource account for 79 percent of the total U.S. peak load reduction potential. Except for direct load control, these programs predominantly enroll wholesale and commercial and industrial customers that bring high per-participant peak load reductions. Direct load control programs are typically targeted to residential and small nonresidential customers; the controllable technologies are relatively homogeneous across these customers. Radio or other communication signals sent by the program sponsor are necessary for effective control of the large numbers of small loads.

Emergency demand response programs (primarily wholesale) account for 24 percent of the peak load reductions, Interruptible Load (primarily commercial and industrial) account for 21 percent of total peak load reductions, and Capacity programs (wholesale and commercial and industrial) account for 15 percent of the peak load reductions. In the 2008 FERC Survey, direct load control ranked first in total peak load reduction potential, and interruptible programs were second. The growth in emergency demand response among wholesale customers is particularly strong: it rises from 3,438 MW in the 2008 FERC Survey to 11,493 in the 2010 FERC Survey, reflecting the growth of RTO demand response resources, as discussed at Figure 4.7. RTO and ISO areas reported growth in peak load reduction capability, which is reflected in the strong increase in Load as a Capacity Resource among wholesale customers; commercial and industrial customers also reported growth in that category. The 2010 FERC Survey received few responses from curtailment service providers (who consider much of their data proprietary), but recent public statements by large curtailment service providers suggest that they manage approximately 10,000 MW of primarily demand response resources (some of which may be among resources submitted by survey respondents).

Figure 4.9. Reported potential peak load reduction by type of program and by customer class



Actual peak load reductions. Respondents were asked to provide information on actual load reductions from demand response during 2009. A number of factors may influence realized reductions. For example, customer electric power consumption when demand response is needed affects the amount of load available to be reduced. Program incentives, penalties, and price signals may also influence participant response. In the U.S., peak demand is strongly influenced by summer heat, and the summer of 2009 had significantly fewer cooling degree-days than the summer of 2007.[31] Finally, net generation in the U.S. during 2009 fell to its lowest level since 2003, the largest such drop in 60 years, accompanying a decline in Gross Domestic Product of 2.6 percent.[32] It is likely that lower electric power consumption, as displayed in Figure 4.10, meant that existing resources were

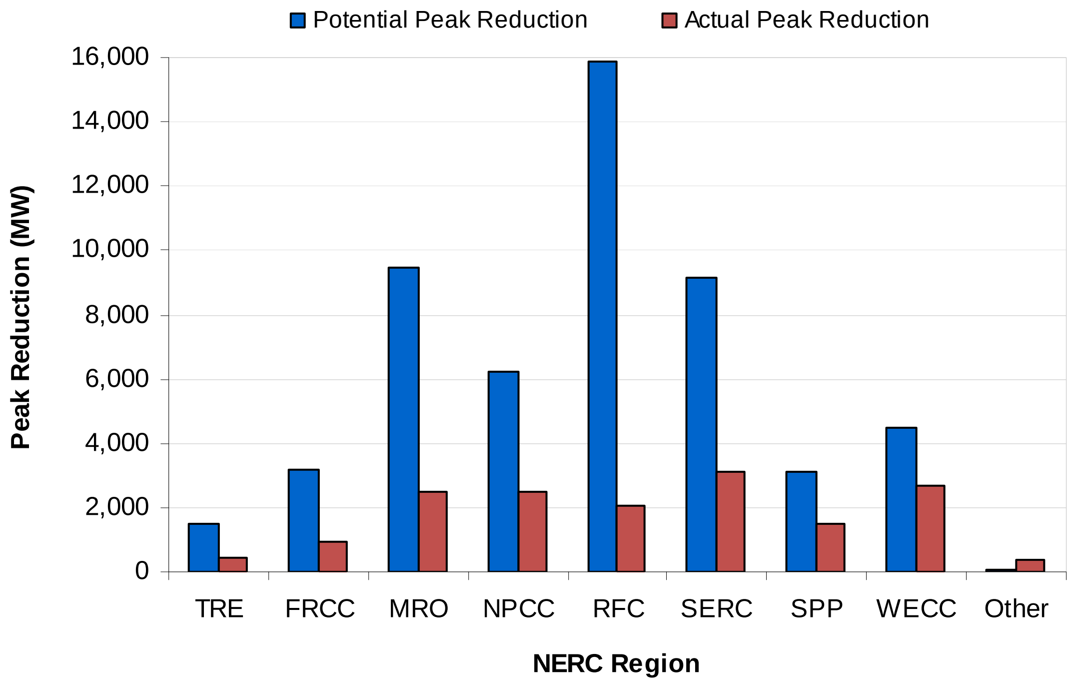
[31] Cooling degree-days (CDD) are a temperature-derived measure used to forecast electrical demand. In the summer of 2007 there were 912 CDDs nationally (weighted by population); in summer 2009 there were 813. (Source: NOAA, Historical Climatology Series 5-2, May 2008 and April 2010).
[32] U.S. Energy Information Administration, Electric Power Annual 2009 (http://eia.gov/cneaf/electricity/epa/epa_sum.html).

adequate to meet load at most times and places, so there were fewer occasions to call on generation, which likely contributed to smaller actual load reductions by demand response resources.

Figure 4.10. Net Annual U.S. Electrical Generation, 2005 through 2009

In total, respondents report 15,980 MW of actual demand response during 2009, equal to 30 percent of the potential peak reduction. In the 2008 FERC Survey 13,398 MW of actual demand response was reported, equal to 36 percent of the potential reduction. Figure 4.11 presents the reported potential and actual 2010 peak load reduction from demand response resources by region. RFC, with the highest potential peak load reduction, called on only 13 percent of its potential. SERC called on about 34 percent of its potential peak load reduction in 2010, while MRO called on 27 percent of its potential load reduction. On the other hand, WECC called on nearly 70 percent of its available peak reduction resources, according to the 2010 FERC Survey.

Figure 4.11. Reported potential and actual 2010 peak load reductions by demand response resources by region



Estimated potential peak load reductions. Commission staff estimated the potential peak reduction of nonresponding entities using FERC Survey data and other sources of information, such as EIA Form 861.[33] The estimates were combined with respondent data to create an estimated potential peak load reduction, by region and customer type, for the entire U.S., as displayed in Figure 4.12.

The estimated potential peak load reduction from demand response resources in the 2010 FERC Survey is 58,339 MW; this is up from the estimated 40,943 MW in the 2008 FERC Survey and the estimated 37,522 MW in 2006 FERC Survey. The rank order of regions with the highest to lowest demand response resources is similar across the three surveys, with RFC region accounting for the majority of demand response resources. Wholesale, commercial and industrial customers combined comprise the highest potential peak load reductions in all regions except FRCC, which has large residential direct load control programs.

[33] The estimation methodology is described in Appendices D and H.

Figure 4.12. Estimated potential peak load reduction by demand response resources by region and customer class

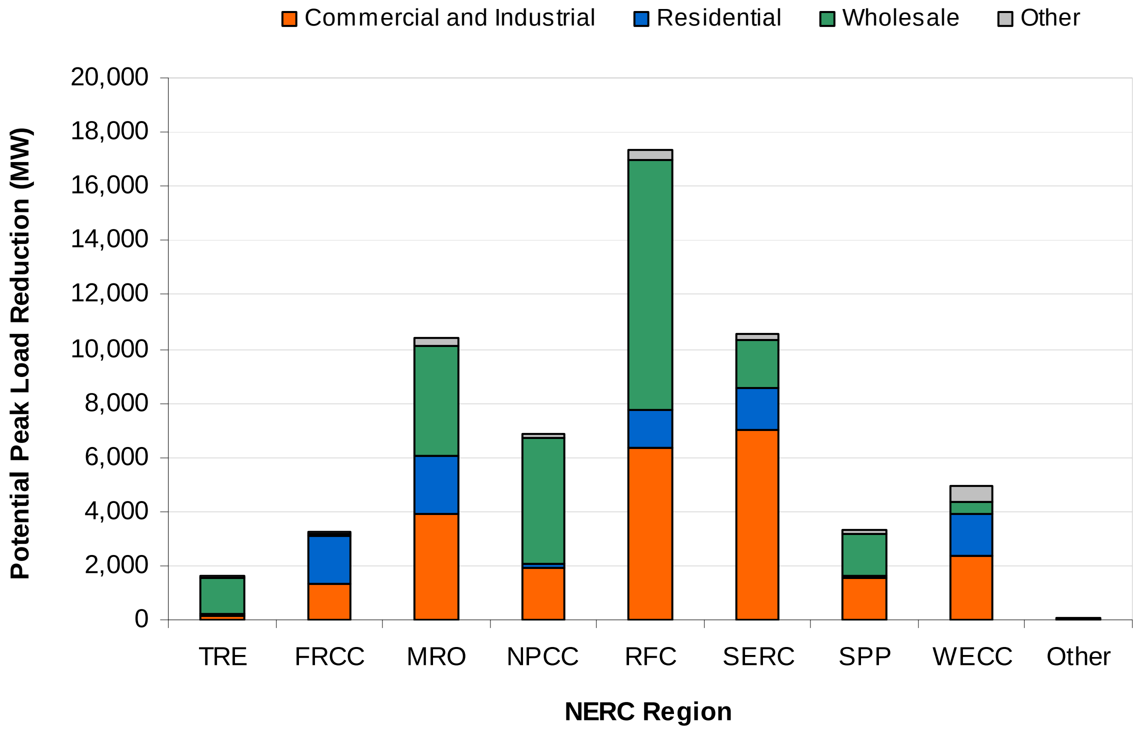


Figure 4.13 presents the estimated potential peak reduction by demand response resources by type of entity and customer class. Investor owned utilities provide the greatest potential, through participation of commercial and industrial load.

Figure 4.13. Estimated potential peak load reduction by demand response resources by type of entity and customer class

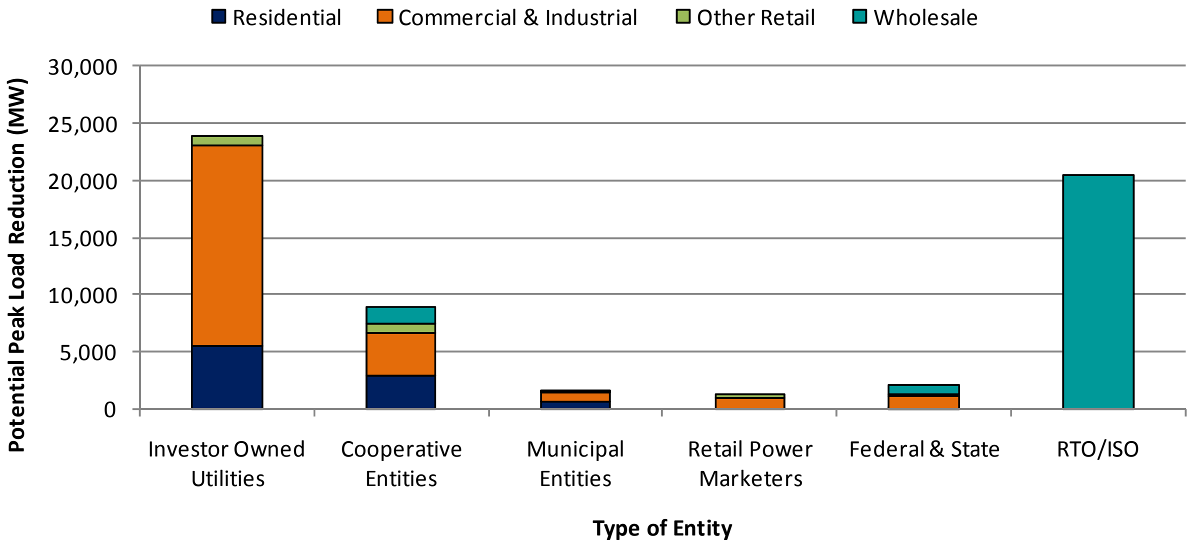


Table 4.2 presents the reported potential peak load reduction by program category and state. According to reported results, all states except for Alaska and Montana have some type of demand response or time-based rate program.

Table 4.2. Reported potential peak load reduction in megawatts by program category and state

State	Time-Based	Direct Load Control	Other Incentive-Based	Emergency Demand Response	Interruptible Load	Other	State Total
AK							0
AL	11	10			1,148	62	1,231
AR	206	198			1,269		1,673
AZ		30			144	-	174
CA	534	785	593	425	457	1	2,795
CO	104	176			191		471
CT			5	752			757
DC			44	40			84
DE			160	128			288
FL	90	2,586	38	25	429	56	3,224
GA	559	230	1		293	-	1,083
HI		20			29		49
IA	5	315	512	23	311		1,166
ID	0	343	0				343
IL	7	60	1,160	1,353	39	-	2,619
IN	46	86	1,304	372	83		1,891
KS	9	26	1	34	125	3	198
KY	67	147	28	1	2		245
LA	1	0			535		536
MA	0		61	601			662
MD	70	14	752	817	11		1,664
ME			1	483			484
MI	3	264	934	44	503		1,748
MN	563	1,453	1,139	229	891	135	4,410
MO	122	73	-	5	217	1	418
MS	100				119		219
MT		0					0
NC	198	317	40	111	1,210	46	1,922
ND	31	22	37	1	68	1	160
NE	2	324		135	170	1,000	1,631
NH		9	7	90			106
NJ	0	2	247	525	8		782
NM	14	58			4	-	76
NV	78	143			40		261
NY	53	42	2,618	972	249		3,934
OH	5	52	610	1,137	287		2,091
OK	823	12	4	420	213		1,472
OR		20					20
PA	18	29	988	1,760	266		3,061
RI			15	110			125
SC	238	43			800	21	1,102
SD	13	418	63	3	55		552
TN			37	15			52
TX	25	135	1,074	1,138	202	5	2,579
UT		113					113
VA	14	144	418	623	18	10	1,227
VT	45	5	3	83	24		160
WA	37	6				-	43
WI	178	288	1,265	98	527	0	2,356
WV			270	487			757
WY	0	8			41		49

Plans for new demand response programs. Respondents were asked to "Provide your entity's near- and long-term plans for new demand response programs and time-based rates/tariffs." Table 4.3 summarizes the responses. Direct load control and critical peak pricing programs (of both types) are prominent among planned new programs, and the expected growth in the number of direct load control programs between 2010 and 2015 is notable. New programs that make use of advanced metering, including critical peak pricing, real-time pricing, and peak-time rebate, increase in number over time, while some of the more traditional load management strategies grow more slowly. Respondents expect the most new potential peak reduction to come from interruptible programs.

Table 4.3. Reported plans for new demand response programs and time-based rates/tariffs

	During Calendar Year 2010		During Calendar Years 2011 and 2012		During Calendar Years 2013 through 2015	
Program Type	Number of Programs	Potential Peak Reduction (MW)	Number of Programs	Potential Peak Reduction (MW)	Number of Programs	Potential Peak Reduction (MW)
Direct Load Control	253	3497	324	4980	563	6301
Interruptible Load	122	7557	119	7771	121	8328
Critical Peak Pricing with Controls	13	234	19	395	22	813
Load as Capacity Resource	36	1393	22	1386	22	915
Spinning Reserves	10	1639	11	1419	10	1390
Non-Spinning Reserves	5	316	8	92	11	232
Emergency Demand Response	53	2027	46	1968	33	3196
Regulation Service	3	105	5	85	6	155
Demand Bidding and Buyback	4	240	6	227	5	425
Time-of-Use Pricing	219	1283	205	1388	193	1489
Critical Peak Pricing	42	354	62	624	66	910
Real-Time Pricing	24	1259	30	1269	29	1271
Peak Time Rebate	13	9	27	643	27	1165
System Peak Response Transmission Tariff	3	36	4	111	3	311
Other	35	2444	27	2436	25	2722

Demand Response Activities at the FERC, Barriers to Demand Response, and Staff Recommendations

Since the publication of the September 2009 *Assessment of Demand Response and Advanced Metering*, the Commission has continued to further the goal of comparable treatment of demand response resources in wholesale markets, as well as to carry out a legislative directive to develop a plan to realize the national potential for demand response.

This chapter summarizes the key demand response developments and actions undertaken by the Commission since the prior report, including issuance of the National Action Plan on Demand Response, several rulemakings, and key demand-response-related RTO orders. It also describes remaining barriers to demand response identified by both the FERC and industry. It concludes with Commission staff recommendations for further action.

National Action Plan on Demand Response

On June 17, 2010, the FERC issued the *National Action Plan on Demand Response* (National Action Plan),[34] a plan for the nation to achieve its potential for cost-effective demand resources through improved coordination of the efforts of utilities, consumers, demand response providers, and federal, state and local officials. As directed by section 529 of the 2007 Energy Independence and Security Act (EISA),[35] the National Action Plan is the product of extensive consultation over two and a half years with a broad range of industry stakeholders including local, state, and federal government officials, utilities, consumers, and nongovernmental groups. The National Action Plan consists of strategies and activities to achieve three objectives: technical assistance to states, a national communications program, and the identification or development of tools and materials for use by customers, states, and demand response providers.

Specific activities identified in the National Action Plan for implementation include the creation of a broad coalition to coordinate and combine the demand response efforts of public and private organizations; the development of technical assistance related to demand response to support state and local decision-making; the development and implementation of

---

[34] *National Action Plan on Demand Response*, Federal Energy Regulatory Commission, June 17, 2010; http://www.ferc.gov/industries/electric/indus-act/demand-response/dr-potential.asp.

[35] 42 U.S.C. § 8279. Section 529 of EISA directed FERC to complete a "National Action Plan on Demand Response" that would:

- (i) identify the requirements for technical assistance to states to allow them to maximize the amount of demand resources that can be developed and deployed;
- (ii) design and identify the requirements for a national communications program that includes broad-based customer education and support; and
- (iii) develop or identify analytical tools, model regulatory provisions, and model contracts for use by customers, states, utilities, and demand response providers.

a national communications plan for demand response;[36] and support for expanded and new analytical tools and materials for demand response analysis and assistance.

Pursuant to section 529 of EISA, the FERC, together with the Secretary of Energy, is to develop of a proposal to implement the National Action Plan and submit the proposal to Congress. The Commission and the U.S. Department of Energy are currently developing this proposal and expect to deliver it to Congress in the near-term.

Commission Rulemakings on Demand Response Issues

Since the previous report in this series issued, the FERC has initiated one new rulemaking related to demand response.

Demand Response Compensation in Organized Wholesale Energy Markets – Notice of Proposed Rulemaking (NOPR)

On March 18, 2010, the Commission issued a proposed rule regarding compensation for demand response providers in organized energy markets.[37] Noting that the levels of compensation for demand response vary significantly among RTOs and ISOs, the Commission questioned whether existing compensation structures are inadequate, and thus may be hindering the development and use of demand response, as demand response providers collectively continue to play a small role in wholesale markets. The NOPR proposed to require RTOs and ISOs to compensate demand response providers for their reductions in usage at the full market price in all hours.

Based on extensive feedback from the initial comments submitted on the proposed rule, the FERC held a staff technical conference on September 13, 2010. There panelists discussed two issues:

- if the Commission were to adopt a net benefits test for determining when to compensate demand response providers, what if any requirements should apply to the methods for determining net benefits; and
- how costs associated with payment for demand response should be allocated within an ISO or RTO.

The FERC invited all stakeholders to submit additional comment on these two issues.

[36] The negative customer reaction to smart meters in Texas and in California, partially due to lack of customer understanding about smart meters, is an example of the importance of proactively informing customers of the benefits and costs of new technology. *See* San Francisco Chronicle, "PG&E probe of SmartMeters to start soon," page DC-1, Available: http://www.sfgate.com/cgi-bin/article.cgi?f=/c/a/2010/03/09/BU3V1CCQSI.DTL&tsp=1 (November 1, 2010).; Public Utility Commission of Texas, "Smart meters superior to traditional ones - Independent study ordered by PUC provides details," August 2, 2010 New Release, Available: http://www.puc.state.tx.us/nrelease/2010/080210.pdf (November 1, 2010).

[37] 130 FERC ¶ 61,213 (March 18, 2010).

Demand Response and Smart Grid Developments

In the past year, many demand response activities—such as using smart meters to control electric loads—have come to overlap considerably with the nation's smart grid initiatives. The FERC has been engaged in two smart grid activities that in part support demand response.

Standards Development for Smart Grid Demand Response Applications

Congress addressed the need for open and interoperable standards in the development of a modern electricity system in EISA. EISA directed NIST to coordinate the development of a framework that includes standards for smart grid devices, many of which will support both advanced metering systems and demand response resources. Section 1305 of the EISA directs the Commission, once it is satisfied that the Institute's work has led to "sufficient consensus" on interoperability standards, to "institute a rulemaking proceeding to adopt such standards and protocols as may be necessary to insure smart-grid functionality and interoperability in interstate transmission of electric power, and regional and wholesale electricity markets."[38]

NIST initiated seventeen Priority Action Plans to facilitate the development of smart grid interoperability standards and has worked closely with other Standards Development Organizations to expedite the development of new standards or the refinement of existing standards.[39] Several of the priority action plans will generate standards that support demand response.[40] On October 6, 2010, NIST notified the FERC that the first set of consensus standards had been posted for review by regulators. The Commission opened a proceeding on these standards on October 7, 2010 with a Notice of Docketed Designation for Smart Grid Interoperability Standards.[41] It also held a technical conference on the posted standards on November 14, 2010, in conjunction with the National Association of Regulatory Utility Commissioners (NARUC)-FERC Collaborative on Smart Response in Atlanta, Georgia.

Coordination of Federal-State Policies

Given the close linkage of federal and state demand response policies, NARUC and the FERC continue to collaborate on demand-side and smart grid issues. In the past year, two NARUC-FERC collaboratives (the Demand Response Collaborative and the Smart Grid Collaborative) were merged into a single NARUC-FERC Collaborative on Smart Response. The mission of the new Collaborative is to provide a forum for federal and state regulators to discuss smart grid and demand response policies, share best practices and technologies, and address issues that benefit from state and federal collaboration. The two collaboratives merged because of the significant overlap of issues and policies.

[38] 42 U.S.C. § 17385 (2006).

[39] Information on the NIST smart grid effort can be found at http://collaborate.nist.gov/twiki-sggrid/bin/view/SmartGrid/WebHome.

[40] In particular, priority action plans 3, 4, 9, 10 and 17.

[41] *See* Docket No. RM11-2 for more information.

Other Demand Response Orders and Activities

The Commission continues to assess and monitor the wholesale electric power markets under its jurisdiction to ensure that demand response resources that are technically capable of providing a service are treated comparably to supply resources. In addition to a set of orders approving various changes to RTO and ISO demand response programs, the FERC issued a series of orders on compliance with the demand response provisions of the Commission's Wholesale Competition Final Rule (Order No. 719). This section summarizes these activities.

As described in the previous two editions of this Report, Order No. 719, issued in October 2008, recognized and reaffirmed the importance of demand response in ensuring just and reasonable wholesale prices and reliable grid operations in organized Regional Transmission Operator (RTO) and Independent System Operator (ISO) markets. Order No. 719 directed the following changes to RTO and ISO market rules:

- accept bids from demand response resources in their markets for certain ancillary services, on a basis comparable to other resources;
- eliminate during a system emergency a charge to a buyer in the energy market for taking less electricity in the real-time market than purchased in the day-ahead market;
- permit aggregators of retail customers to bid demand response on behalf of retail customers directly into the organized energy market in certain circumstances; and
- modify their market rules, as necessary, to allow the market-clearing price during periods of operating-reserve shortage to reach a level that rebalances supply and demand so as to maintain reliability while providing sufficient provisions for mitigating market power.

In Order Nos. 719-A and 719-B, issued in July and December 2009 respectively,[42] the Commission addressed several additional issues, including demand response participation in organized markets and the role of the relevant electric retail regulatory authority. The Commission directed that RTOs and ISOs (1) must accept bids from aggregators of demand response from retail customers of utilities that distributed more than 4 million MWh in the previous fiscal year, except where prohibited by the relevant electric retail regulatory authority, and (2) must not accept bids from aggregators of demand response from retail customers of utilities that distributed 4 million MWh or less during in the previous fiscal year, unless permitted by the relevant electric retail regulatory authority.

Order No. 719 required each of the six RTOs and ISOs to submit filings either proposing tariff amendments to comply with the rule's requirements or to demonstrate that its existing

[42] *Wholesale Competition in Regions with Organized Electric Markets*, Order No 719-A, 128 FERC ¶ 61,059 (July 16, 2009) (Order No. 719-A), *reh'g den*, Order No. 719-B, 129 FERC ¶ 61,252 (December 17, 2009).

tariff and market design already are in compliance. The six RTOs and ISOs submitted their filings in individual dockets in April and May of 2009. In general, the RTOs and ISOs asserted in their compliance filings that they either already were in compliance with the Order No. 719 demand response requirements, or were working toward compliance. After substantial comment by stakeholders, the FERC issued initial orders finding that the RTOs and ISOs already had taken steps to eliminate some of the barriers to demand response participation within their markets, and directing the RTOs and ISOs to make additional filings to address remaining areas of noncompliance.

California ISO

The FERC accepted several Order No. 719 compliance filings related to demand response from the California ISO (CAISO). In June 2010, it conditionally accepted CAISO's filing to implement a Scarcity Pricing Mechanism, for pricing of energy and ancillary services during periods of operating reserve shortages, to meet Order No. 719's requirements for operating reserve shortage pricing.[43] The Scarcity Pricing Mechanism applies when a shortage condition is triggered: when supply is insufficient to meet one or more of the CAISO's ancillary services requirements within an ancillary service region or subregion. The price of the affected ancillary service(s) is set by administratively-determined demand curves, and will apply to the region or subregion in which the shortage occurs. In July 2010, the FERC conditionally accepted CAISO's proposal to permit a demand response provider to bid demand response on behalf of retail customers directly into the CAISO's organized markets, as required by Order No. 719.[44] The proposal introduced a new demand response product to the CAISO markets, the proxy demand resource, defined as a load or an aggregation of loads capable of measurably and verifiably reducing electric demand in response to CAISO dispatch instructions. In September 2010, the Commission conditionally accepted CAISO's proposed tariff revisions to facilitate the provision of ancillary services by demand resources,[45] finding them to be an incremental step toward removing barriers to comparable treatment of nongenerator resources to provide ancillary service products.

ISO New England

In a series of orders, the FERC accepted changes to ISO-NE's market rules related to demand response that comply with Order No. 719. In a January 2010 order on ISO-NE's compliance filing,[46] the Commission stated that ISO-NE must demonstrate how "dispatchable-asset-related demand" (DARD) resources or any revised mechanism complies with the comparability requirements of Order No. 719 as they pertain to the provision of ancillary

[43] *California Independent System Operator Corporation*, 131 FERC ¶ 61,280 (June 29, 2010), *reh'g pending*.
[44] *California Independent System Operator Corporation*, 132 FERC ¶ 61,045 (July 15, 2010), *reh'g pending.* As part of this proposal, the California Public Utilities Commission held hearings. *See* Cal. Pub. Utils. Comm'n, *Assigned Commissioner And Administrative Law Judges' Ruling Amending Scoping Memo, Establishing A Direct Participation Phase Of This Proceeding, And Requesting Comment On Direct Participation Of Retail Demand Response In CAISO Electricity Markets*, 07-01-41 (Nov. 9, 2009), *available at* http://docs.cpuc.ca.gov/efile/RULINGS/109611.pdf); *see also* Cal. Pub. Utils. Comm'n, *Decision on Phase Four Direct Participation Issues*, 07-01-041 (June 4, 2010), *available at* http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/118962.pdf.
[45] *California Independent System Operator Corporation*, 132 FERC ¶ 61,211 (September 10, 2010).
[46] *ISO New England Inc. and New England Power Pool*, 130 FERC ¶ 61,054 (January 21, 2010).

services. In response, ISO-NE filed and the Commission accepted revisions to its market rules to reduce the minimum size requirement for DARD from 5 MW to 1 MW, and to allow aggregation of retail customers receiving electrical service from the same point of supply. The Commission also accepted tariff revisions to eliminate differences in the treatment of third-party aggregators of retail customers and host utilities with respect to their ability to aggregate customers for purposes of providing demand response resources.[47]

The FERC also accepted a change to ISO-NE's Forward Capacity Market (FCM) rules to prevent most demand resources from being subject to performance penalty charges that exceed their FCM revenues in a month. The changes also closely tie the penalty and incentive rates for demand resources to their FCM payment rates.[48]

New York ISO

In its April 2009 Order No. 719 compliance filing, the New York ISO (NYISO) stated that it either already is in compliance, or soon would be, with the requirements of the order regarding demand response bidding flexibility, scarcity pricing, and operating reserve. In its order conditionally accepting NYISO's filing, the Commission directed NYISO to explain the reasonableness of its requirement that demand response resources use the same telemetry and communications equipment used by generators, and to provide a timeline for demand response resource integration into its energy market. It also directed NYISO to file its market rules governing the ability of aggregators to bid directly into the ancillary services market.[49] In a follow-up filing, NYISO estimated that demand response resource integration would be unlikely to occur prior to the middle of 2012, and agreed to submit semiannual updates on progress on evaluating possible communication alternatives for demand response and its plan of action for the real-time energy market demand response resource integration.[50]

PJM Interconnection, L.L.C.

On February 9, 2009, PJM filed proposed tariff changes to clarify the right of a retail regulatory authority to prohibit participation of a retail customer in PJM's demand response programs. In a series of orders, the Commission accepted tariff changes that (i) recognize a retail regulatory authority's ability to condition the eligibility of its retail customers to participate in PJM's demand response programs, (ii) address how retail regulatory prohibitions would affect existing registrations and commitments made by PJM market participants, and (iii) obligate PJM to post on its website a list of retail regulatory authorities that prohibit retail participation in PJM's Demand Response Programs.[51] In addition, the Commission clarified that, while it would not require PJM to disclose customer-specific

[47] *ISO New England Inc. and New England Power Pool*, Docket No. ER09-1051-003 (July 23, 2010); *ISO New England Inc. and New England Power Pool*, Docket No. ER09-1051-004 (Sept. 29, 2010) (letter orders).
[48] *ISO New England Inc. and New England Power Pool*, Docket No. ER10-2232 (October 1, 2010).
[49] *New York Independent System Operator*, 129 FERC ¶ 61,164 (2009), *reh'g*, 131 FERC ¶ 61,114 (2010).
[50] *New York Independent System Operator*, Docket No. ER09-1142-006 (April 23, 2010) (letter order).
[51] *See PJM Interconnection, L.L.C.*, 128 FERC ¶ 61,238 (2009) and *PJM Interconnection, L.L.C.*, 131 FERC ¶ 61,069 (April 23, 2010). The April 23 order is now pending before the US Court of Appeals for the 7th Circuit, on a petition for review filed by the Indiana Utility Regulatory Commission.

confidential or proprietary information regarding demand response participation, this would not affect any rights of a state commission to obtain such information.

Southwest Power Pool

In its order on the Southwest Power Pool's (SPP) Order No. 719 compliance filing,[52] the Commission directed SPP to submit a revised filing to address comparability in a way that enables demand response resources to participate on terms that both address the characteristics of demand response resources and ensure reliable operations. Specifically, it directed SPP to revise its tariff to allow demand response resources, including bids from aggregators, to participate in SPP's energy markets on a basis comparable to other resources. The Commission stated that SPP did not justify why technical requirements, policies, and procedures tailored for generation resources are reasonable and appropriate for accommodating the characteristics of technically capable demand response resources. It also rejected SPP's proposed method for determining a customer's baseline electric consumption, and found that SPP had not proposed a measurement and verification standard as required by Order No. 719. SPP was directed to address these deficiencies in a compliance filing. SPP filed a further compliance on demand response on May 19, 2010.

Further Barriers to Demand Response

This section summarizes the barriers to demand response in organized markets identified by the RTOs and ISO in the Order No. 719 process, and also other barriers identified outside that process.

Barriers to Demand Participation in Organized Wholesale Markets

In response to the direction in Order No. 719, each of the RTOs and ISOs studied the need for further reforms to remove barriers to comparable treatment of demand response resources.[53] A review of the filed RTO and ISO barriers filings, including comments on the filings, identified several remaining barriers. Several of the identified barriers are the subject of additional compliance filings and orders that are discussed in section IV. Such barriers include:

- **Use of generator-specific models and offer parameters.** Commenters contended that the ISOs and RTOs continue to impose offer parameter requirements that do not adequately recognize the different characteristics of demand response and traditional generation resources and, therefore, do not provide for comparable treatment of demand response resources as required by Order No. 719.
- **Shortage pricing.** As identified in Order No. 719 and by several commenters, many of the RTOs and ISOs' shortage pricing mechanisms may not accurately reflect shortages because they are triggered only after emergency provisions are initiated. Market rule changes to implement shortage pricing were included in several of the RTO compliance filings.

---

[52] *Southwest Power Pool, Inc.*, 129 FERC ¶ 61,163 (Nov. 20, 2009), *reh'g pending.*
[53] Order No. 719, P 274.

- **Reliability standards on ancillary services**. Regional reliability standards imposed on RTOs and ISOs may restrict or prevent the participation of demand response resources in ancillary services markets.[54]

During the Order No. 719 proceeding, several additional barriers to demand response participation were identified by commenters, and were not directly addressed in the Rule. These include:

- **Telemetry requirements.** Unnecessary or onerous telemetry requirements for demand response resources have been cited as a barrier to greater demand response participation. Telemetry refers to near instantaneous metering and transfer of electricity consumption data to system operators. Commenters in the Order No. 719 proceeding argued that in certain wholesale markets demand-side resources should not be subject to the same telemetry requirements as supply-side resources.
- **Price Transparency in Bilateral Capacity Markets.** Commenters identified the lack of price transparency for the capacity value of demand response resources as a barrier in RTO and ISO regions that lack a centralized forward capacity market. Lacking a centralized forward capacity market, commenters argued, demand response resources must rely on bilateral contracts that may not provide the price transparency necessary to ensure that these resources are fairly compensated and to encourage additional provision of capacity by new demand response resources.
- **Market Monitoring and Mitigation.** Commenters noted that a relatively new issue is whether demand response providers can exercise market power and thus should be subject to mitigation and scrutiny from market monitors. Because this issue has not been thoroughly addressed, demand response providers may be reluctant to bid in during periods of high prices due to concerns regarding exercising market power, especially if their bids are eligible to set the market clearing price.

Other Barriers to Demand Response

In addition to the barriers identified and addressed in FERC proceedings, federal, state, and local policy makers over the past several years have identified several additional key regulatory barriers to greater demand response, at both the federal and the state levels.

Financial and Pricing Impacts Associated with Offering Demand Response

Disincentives to investment in demand-side resources (which include both energy efficiency and reliability-based demand response resources) are imbedded in rate structures and regulation. Utilities generally earn revenue based on the amount of electricity they sell. If electricity consumption decreases during peak periods due to demand response initiatives and is not shifted to off-peak hours, utilities could lose revenue.

---

[54] For example, the Western Electricity Coordinating Council (WECC) currently does not allow loads to provide spinning reserve. *See* NERC, *Special Report: Potential Reliability Impacts of Emerging Flexible Resources*, August 2010.

As reported in prior FERC annual demand response reports and the National Assessment, many states and the FERC are exploring and implementing new policies to reduce disincentives to investment in demand-side resources.[55]

Limited Number of Retail Customers on Time-Based Rates

The National Assessment of Demand Response Potential identified significant demand reduction potential if retail customers were on time-based rates.[56] Heightened interest in the topic is evidenced by more than fifteen smart grid and demand response pilots that have been conducted since the mid-1990s.[57] There have been only limited implementation of time-based rates and tariffs, both for optional programs that customers can voluntarily join and for programs in which this is the default rate (which in some cases the customer may "opt-out" of). California is one of the few states that have adopted a critical peak pricing tariff as its default rate for commercial and industrial customers. In the few states where time-based rates have been approved, the focus has been on peak time rebates (i.e., where customers can earn a rebate by reducing energy use from a baseline during a specified number of hours on critical peak days), limiting experience with other time-based rates. For example, in its approval of Baltimore Gas & Electric's smart grid plans, the Maryland PSC rejected the proposed critical peak pricing rates and approved only peak time rebates.[58]

Measurement and Cost-Effectiveness of Reductions

How to effectively estimate a customer's baseline electricity use is a primary issue in the measurement and verification of demand response. In RTO and ISO markets, participants in demand response programs measure their reductions by comparing actual meter readings against an estimate of what metered load would have been without the reduction in demand—the customer baseline. The RTOs and ISOs use various baseline methods to estimate consumption without demand response.[59] Efforts to improve and standardize baseline estimates are underway at the state and industry levels.[60] Since 2008, the North American Energy Standards Board (NAESB) has been developing business practice standards for measurement and verification of demand reductions by demand response

[55] *See*, for example, the Institute of Energy Efficiency's July 2010 summary of State Electric Efficiency Regulatory Framework for a summary of state activity: http://www.edisonfoundation.net/iee/issueBriefs/IEE_StateRegulatoryFrame_0710.pdf, and discussion of Wholesale Competition in Regions with Organized Markets – Order No. 719, supra.

[56] The National Assessment projects that peak demand reductions close to 20 percent of peak load in 2019 could achieved if all customers were on mandatory dynamic pricing.

[57] Faruqui, Ahmad and Sergici, Sanem, "Household Response to Dynamic Pricing of Electricity - A Survey of the Empirical Evidence," *Journal of Regulatory Economics*, 38:193-225.

[58] Supra note 29.

[59] The *North American Wholesale Electricity Demand Response 2010 Comparison* developed by the ISO/RTO Council documents the various baseline methodologies in use. *See* http://www.isorto.org/site/apps/nlnet/content2.aspx?c=jhKQIZPBImE&b=2613997&ct=8400541.

[60] For example, California continues to examine demand response impact and cost-effectiveness in one of its proceedings. *See* http://docs.cpuc.ca.gov/published/proceedings/R0701041.htm for more information.

resources at both the wholesale and retail levels.[61] The FERC approved Phase I of the wholesale standards in April 2010.[62] Work continues at NAESB on Phase II of these standards. As the Commission stated in its April order, "we expect Phase II will address issues related to baseline deployment."[63]

Efforts continue to develop cost-effectiveness methods to assess demand response and smart grid investments, with a particular focus on estimating benefits. Business cases filed with state regulators typically include in their benefit estimates both improved operational efficiencies and projected lowered energy and capacity costs. The size and certainty of these energy and capacity cost savings have been questioned during state deliberations.[64] In addition, questions of the scope of the cost-effectiveness calculations have been raised, e.g., whether in-home displays and other tools for customers should be included in the costs of a program.

Cost Recovery and Incentives for Enabling Technologies

The investments in devices, controls and software to implement demand response remain one of the greatest barriers to increased penetration. Regulatory approaches to cost recovery for these devices, controls and software are being addressed in state rate cases and proceedings**.**[65] The federal government through the American Recovery and Reinvestment Act funded $4.5 billion in smart grid and demand response. Additional attention to best practices in cost recovery is needed, particularly to resolve the issue of who should bear the initial cost of smart grid investments installation and implementation.

New Environmental Rule Covering the Operation of Emergency Generators

In March 2010, the U.S. Environmental Protection Agency (EPA) issued a final rule setting national emission standards for hazardous air pollutants for existing stationary compression ignition reciprocating internal combustion engines (i.e., diesel generators).[66] Diesel emergency generators covered in the final rule may operate up to 15 hours as part of RTO emergency demand response programs. This 15 hour cap is less than the minimum number

[61] North American Energy Standards Board, http://www.naesb.org/dsm-ee.asp.
[62] Standards for Business Practices and Communication Protocols for Public Utilities, Final Rule, Order No. 676-F, 75 FR 20901 (April 15, 2010).
[63] Ibid, P 37.
[64] For example, in Maryland PSC's conditional approval of Baltimore Gas & Electric's smart grid plans in Order No. 83531, the PSC raises questions about the speculative nature of these benefits – http://webapp.psc.state.md.us/Intranet/sitesearch/CN9208.pdf. California PUC's 07-01-041 proceedings is also addressing these issues, *see supra note* 5.
[65] For example, the Maryland PSC initially rejected Baltimore Gas & Electric's proposed rate surcharge to recover the costs of their smart grid plans. The final order approved BG&E's proposal but deferred decisions on recovery. Recently, the Appellate Court of Illinois ruled that a special surcharge created to pay for a smart grid pilot did not meet the criteria to warrant single-issue ratemaking and put into doubt the future of the pilot**,** *see* http://www.state.il.us/court/Opinions/AppellateCourt/2010/2ndDistrict/September/2080959.pdf.
[66] *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines*, Final Rule, 75 FR 9648 (March 3, 2010).

of hours (typically 60) that are required for participation in RTO emergency demand response programs. Several curtailment service providers petitioned EPA to reconsider the final rule, arguing that the rule would not allow customers with covered diesel generators to participate in RTO programs (emergency generators are used by many customers "behind-the-meter" to create load reductions); thereby reducing the level of the demand response available. The EPA recently requested comments on whether the 15 hour limitation should be changed.[67]

Staff Recommendations

As directed by EISA, FERC staff prepared a detailed set of recommended activities that should be undertaken by federal, state and local policymakers to achieve the potential identified in the 2009 *National Assessment of Demand Response Potential*. These activities are set out in detail in the National Action Plan and are designed to address many of the challenges and barriers to the deployment of demand response resources discussed above.

---

[67] *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines*, Notice of reconsideration of final rule; request for public comment; notice of public meeting, 75 FR 75937 (December 7, 2010).

APPENDIX A: SECTION 1252 OF THE ENERGY POLICY ACT OF 2005

SEC. 1252. SMART METERING.

(a) IN GENERAL.—Section 111(d) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2621(d)) is amended by adding at the end the following:

‘‘(14) TIME-BASED METERING AND COMMUNICATIONS.—

(A) Not later than 18 months after the date of enactment of this paragraph, each electric utility shall offer each of its customer H. R. 6—371 classes, and provide individual customers upon customer request, a time-based rate schedule under which the rate charged by the electric utility varies during different time periods and reflects the variance, if any, in the utility’s costs of generating and purchasing electricity at the wholesale level. The time-based rate schedule shall enable the electric consumer to manage energy use and cost through advanced metering and communications technology.

‘‘(B) The types of time-based rate schedules that may be offered under the schedule referred to in subparagraph (A) include, among others—

‘‘(i) time-of-use pricing whereby electricity prices are set for a specific time period on an advance or forward basis, typically not changing more often than twice a year, based on the utility’s cost of generating and/or purchasing such electricity at the wholesale level for the benefit of the consumer. Prices paid for energy consumed during these periods shall be pre-established and known to consumers in advance of such consumption, allowing them to vary their demand and usage in response to such prices and manage their energy costs by shifting usage to a lower cost period or reducing their consumption overall;

‘‘(ii) critical peak pricing whereby time-of-use prices are in effect except for certain peak days, when prices may reflect the costs of generating and/or purchasing electricity at the wholesale level and when consumers may receive additional discounts for reducing peak period energy consumption;

‘‘(iii) real-time pricing whereby electricity prices are set for a specific time period on an advanced or forward basis, reflecting the utility’s cost of generating and/or purchasing electricity at the wholesale level, and may change as often as hourly; and

‘‘(iv) credits for consumers with large loads who enter into pre-established peak load reduction agreements that reduce a utility’s planned capacity obligations.

‘‘(C) Each electric utility subject to subparagraph (A) shall provide each customer requesting a time-based rate with a time-based meter capable of enabling the utility and customer to offer and receive such rate, respectively.

‘‘(D) For purposes of implementing this paragraph, any reference contained in this section to the date of enactment of the Public Utility Regulatory Policies Act of 1978 shall be deemed to be a reference to the date of enactment of this paragraph.

‘‘(E) In a State that permits third-party marketers to sell electric energy to retail electric consumers, such consumers shall be entitled to receive the same time-based metering and communications device and service as a retail electric consumer of the electric utility.

‘‘(F) Notwithstanding subsections (b) and (c) of section 112, each State regulatory authority shall, not later than 18 months after the date of enactment of this paragraph conduct an investigation in accordance with section 115(i) and issue a decision whether it is appropriate to implement the standards set out in subparagraphs (A) and (C).’’. H. R. 6—372

(b) STATE INVESTIGATION OF DEMAND RESPONSE AND TIMEBASED METERING.—Section
115 of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2625) is amended as follows:
(1) By inserting in subsection (b) after the phrase ‘‘the standard for time-of-day rates established by section 111(d)(3)’’ the following: ‘‘and the standard for time-based metering and communications established by section 111(d)(14)’’.
(2) By inserting in subsection (b) after the phrase ‘‘are likely to exceed the metering’’ the following: ‘‘and communications’’.
(3) By adding at the end the following:
‘‘(i) TIME-BASED METERING AND COMMUNICATIONS.—In making a determination with respect to the standard established by section 111(d)(14), the investigation requirement of section 111(d)(14)(F) shall be as follows: Each State regulatory authority shall conduct an investigation and issue a decision whether or not it is appropriate for electric utilities to provide and install time-based meters and communications devices for each of their customers which enable such customers to participate in time-based pricing rate schedules and other demand response programs.’’.

(c) FEDERAL ASSISTANCE ON DEMAND RESPONSE.—Section 132(a) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2642(a)) is amended by striking ‘‘and’’ at the end of paragraph (3), striking the period at the end of paragraph (4) and inserting ‘‘; and’’, and by adding the following at the end thereof: ‘‘(5) technologies, techniques, and rate-making methods related to advanced metering and communications and the use of these technologies, techniques and methods in demand response programs.’’.

(d) FEDERAL GUIDANCE.—Section 132 of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2642) is amended by adding the following at the end thereof:
‘‘(d) DEMAND RESPONSE.—The Secretary shall be responsible for—
‘‘(1) educating consumers on the availability, advantages, and benefits of advanced metering and communications technologies, including the funding of demonstration or pilot projects;
‘‘(2) working with States, utilities, other energy providers and advanced metering and communications experts to identify and address barriers to the adoption of demand response programs; and
‘‘(3) not later than 180 days after the date of enactment of the Energy Policy Act of 2005, providing Congress with a report that identifies and quantifies the national benefits of demand response and makes a recommendation on achieving specific levels of such benefits by January 1, 2007.’’.

(e) DEMAND RESPONSE AND REGIONAL COORDINATION.—
(1) IN GENERAL.—It is the policy of the United States to encourage States to coordinate, on a regional basis, State energy policies to provide reliable and affordable demand response services to the public.
(2) TECHNICAL ASSISTANCE.—The Secretary shall provide technical assistance to States and regional organizations formed by two or more States to assist them in—

(A) identifying the areas with the greatest demand response potential; H. R. 6—373

(B) identifying and resolving problems in transmission and distribution networks, including through the use of demand response;

(C) developing plans and programs to use demand response to respond to peak demand or emergency needs; and

(D) identifying specific measures consumers can take to participate in these demand response programs.

(3) REPORT.—Not later than 1 year after the date of enactment of the Energy Policy Act of 2005, the

Commission shall prepare and publish an annual report, by appropriate region, that assesses demand response resources, including those available from all consumer classes, and which identifies and reviews—

(A) saturation and penetration rate of advanced meters and communications technologies, devices and systems;

(B) existing demand response programs and time-based rate programs;

(C) the annual resource contribution of demand resources;

(D) the potential for demand response as a quantifiable, reliable resource for regional planning purposes

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

(F) regulatory barriers to improve customer participation in demand response, peak reduction and critical period pricing programs.

(f) FEDERAL ENCOURAGEMENT OF DEMAND RESPONSE DEVICES.—It is the policy of the United States that time-based pricing and other forms of demand response, whereby electricity customers are provided with electricity price signals and the ability to benefit by responding to them, shall be encouraged, the deployment of such technology and devices that enable electricity customers to participate in such pricing and demand response systems shall be facilitated, and unnecessary barriers to demand response participation in energy, capacity and ancillary service markets shall be eliminated. It is further the policy of the United States that the benefits of such demand response that accrue to those not deploying such technology and devices, but who are part of the same regional electricity entity, shall be recognized.

(g) TIME LIMITATIONS.—Section 112(b) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2622(b)) is amended by adding at the end the following:

''(4)(A) Not later than 1 year after the enactment of this paragraph, each State regulatory authority (with respect to teach electric utility for which it has ratemaking authority) and each nonregulated electric utility shall commence the consideration referred to in section 111, or set a hearing date for such consideration, with respect to the standard established by paragraph (14) of section 111(d).

''(B) Not later than 2 years after the date of the enactment of this paragraph, each State regulatory authority (with respect to each electric utility for which it has ratemaking authority), and each non-regulated electric utility, shall complete the consideration, and shall make the determination, referred to in section 111 with respect to the standard established by paragraph (14) of section 111(d).'

APPENDIX B: ABBREVIATED NAMES AND ACRONYMS USED IN THIS REPORT

AMI	Advanced Metering Infrastructure
AMR	Automated Meter Reading OR Automatic Meter Reading
ANSI	American National Standards Institute
ASCC	Alaska Systems Coordinating Council
CAISO	California Independent System Operator
EIA	Energy Information Administration
EISA 2007	Energy Independence and Security Act of 2007
EPAct 2005	Energy Policy Act of 2005
ERCOT	Electric Reliability Council of Texas, Inc.
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
G&T	Generation and Transmission
HEFPA	Home Energy Fair Practices Act
kW	Kilowatt
kWh	Kilowatt-hour
ISO	Independent System Operator
ISO-NE	Independent System Operator of New England
LaaR	Load acting as a resource (ERCOT category)
MADRI	Mid-Atlantic Distributed Resources Initiative
MISO	Midwest Independent System Operator
MRO	Midwest Reliability Organization
MRTU	Market redesign and technology update
MWDRI	Midwest Demand Response Initiative
MW	Megawatt
MWh	Megawatt-hour
NAESB	North American Energy Standards Board
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
NYISO	New York Independent System Operator
OATT	Open Access Transmission Tariff
PJM	PJM Interconnection, L.L.C
RFC	Reliability*First* Corporation
RPM	Reliability Pricing Model
RTO	Regional Transmission Organization
SERC	SERC Reliability Corporation
SPP	Southwest Power Pool, Inc.
SPPR	Southwest Power Pool Regional Entity
TRE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Appendix C: Survey Glossary

The terms and definitions in this glossary were provided to survey respondents and are for the limited purpose of the survey.

Actual MWh Change: The total change in energy consumption (measured in MWh) that resulted from the deployment of demand response programs during the year.

Advanced Meters: Meters that measure and record usage data at hourly intervals or more frequently, and provide usage data to both consumers and energy companies at least once daily. Data are used for billing and other purposes. Advanced meters include basic hourly interval meters, meters with one-way communication, and real-time meters with built-in two-way communication capable of recording and transmitting instantaneous data.

Aggregator: See "**Curtailment Service Provider**"

Ancillary Services: Services that ensure reliability and support the transmission of electricity to customer loads. Such services may include: energy imbalance, operating reserves, contingency reserves, spinning (also known as synchronized, ten-minute spinning, responsive) reserves, supplemental (also known as non-spinning, non-synchronized, ten-minute non-synchronous, thirty-minute operating) reserves, reactive supply and voltage control, and regulation and frequency response (also known as regulation reserves, regulation service, up-regulation and down-regulation).

Bid Limit: The maximum bid, in $/MWh, that can be submitted by a demand response program participant. If there is no bid limit, leave blank.

Capacity (program type): Displacement or augmentation of generation for planning and/or operating resource adequacy; penalties are assessed for nonperformance.

Capacity Market Programs: Arrangements in which customers offer load reductions as system capacity to replace conventional generation or delivery resources. Participating customers typically receive notice of events requiring a load reduction and face penalties when failing to curtail load. Incentives usually consist of up-front reservation payments.

Capacity Service: A type of demand response service in which **demand resources** are obligated over a defined period of time to be an available resource for the system operator.

Commercial and Industrial: Belonging to either of the energy-consuming sectors that consist of (a) a broad range of facility types including office buildings, retail establishments, hospitals, universities, the facilities of federal, state, and local governments and nonprofit organizations, institutional living quarters, master-metered apartment buildings, and homes on military bases; and (b) manufacturing facilities and equipment used for producing, processing, or assembling goods and encompassing the following types of activities: manufacturing; processing; agriculture, forestry and fisheries; mining; and construction. Also, a business labeled as "industrial" by the North American Industry Classification System or by the energy provider on the basis of energy demand or annual usage exceeding some specified limit set by the energy provider.

Coincident Reduction Capability: The amount of demand response curtailments that would be realized if all demand response products were called simultaneously and all responded by curtailing load at prearranged levels or at their enrolled quantity.

Critical Peak Pricing with Load Control: Demand-side management that combines direct load control with a pre-specified high price for use during designated critical peak periods, triggered by system contingencies or high wholesale market prices.

Critical Peak Pricing: Rate and/or price structure designed to encourage reduced consumption during periods of high wholesale market prices or system contingencies by imposing a pre-specified high rate or price for a limited number of days or hours.

Curtailment Service Provider: Businesses that sponsor demand response programs that recruit and contract with end users, and sell the aggregated demand response to utilities, RTOs and ISOs. A Curtailment Service Provider is sometimes called an Aggregator and is not necessarily a load-serving entity.

Customer Sector: A group of customers: **residential, commercial and industrial**, and **other** (for example, **transportation**, **agricultural**).

Demand Bidding & Buy-Back: A program which allows a demand resource in retail and wholesale markets to offer load reductions at a price, or to identify how much load it is willing to curtail at a specific price.

Demand Resource or Demand-Side Resource: An electricity consumer that can decrease its power consumption in response to a price signal or direction from a system operator.

Demand Response: Changes in electric use by demand-side resources from their normal consumption patterns in response to changes in the price of electricity, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.

Demand Response Program: A company's service/program/tariff related to demand response, or the change in customer electric usage from normal consumption patterns in response to changes in the price of electricity over time or in response to incentive payments designed to induce lower electricity use at times of high wholesale market prices, or a change in electric usage by end-use customers at the direction of a system operator or an automated preprogrammed control system when system reliability is jeopardized. Includes both time-based rate programs and incentive-based programs.

Demand Response Program/Tariff and Program/Tariff Types: A company or utility's service/product/compilation of all effective rate schedules, general terms and conditions and standard forms related to demand response and/or AMI services and classification thereof.

Direct Load Control: A demand response activity by which the program sponsor remotely shuts down or cycles a customer’s electrical equipment (e.g. air conditioner, water heater) on short notice. Direct load control programs are primarily offered to residential or small commercial customers. Also known as direct control load management.

Display Unit/In-home Display: Customer on-site device that receives (from a service provider or from a smart meter) and displays for the customer information such as usage and pricing data, messages, and alerts.

Duration of Event: The length of an Emergency or Economic Demand Response Event, in hours.

Economic Demand Response Event: An event in which the demand response program sponsor directs response to an economic market opportunity, rather than for reliability or because of an emergency in the energy delivery system.

Electric Utility: A corporation, person, agency, authority, or other legal entity or instrumentality producing, transmitting, or distributing electricity for use primarily by the public. This includes: investor-owned electric utilities, municipal and state utilities, federal electric utilities, and rural electric cooperatives. A few entities that are tariff based and affiliated with companies owning distribution facilities are also included in this definition.

Emergency Event: An abnormal system condition (for example, system constraints and local capacity constraints) that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System.

Emergency Demand Response Event: The period of time during which participants in a Demand Response Program must reduce load. The Emergency Demand Response Event is announced by the program sponsor in response to an Emergency Event declared by it or by another entity such as a utility or RTO/ISO. Demand Response Program sponsors, utilities and RTO/ISOs typically declare these emergency events.

Emergency Demand Response Program: A demand response program that provides incentive payments to customers for load reductions achieved during an Emergency Demand Response Event.

End-Use Customer: A firm or individual that purchases electricity for its own consumption and not for resale; an ultimate consumer of electricity.

Energy Payment for MWh Curtailed ($/MWh): Compensation paid or received for reductions in electric energy consumption.

Energy Service Providers: See **Power Marketers**.

Entity: The organization that is (1) responding to the survey, (2) offering demand response programs, time-based rates and/or tariffs, or (3) using advanced or smart meters.

Entity ID Number: The respondent should enter the ID number which appears on the survey transmittal e-mail, or the ID number used for the entity's response to Form EIA-861.

Event Limits: The maximum number of times a demand response resource may be called during a specified period of time (typically one year or one season).

Federal Electric Utility: A utility that is either owned or financed by the Federal Government.

Generation and Transmission Company (G&T Company): A company that provides both energy production and facilities for transmitting energy to wholesale customers. G&T companies are usually formed by rural electric cooperatives and electric utilities to pool the costs and risks of constructing and managing the generation facilities and high-voltage transmission infrastructure which are needed to deliver energy to their customers.

Hourly Pricing: A pricing plan in which energy prices vary by the hour, usually based in part on a wholesale market price for energy.

In-home Display: See **Display Unit/In-home Display**.

Industrial Sector: The energy-consuming sector that consists of manufacturing facilities and equipment used for producing, processing, or assembling goods. The Industrial Sector encompasses the following types of activities: manufacturing; processing; agriculture, forestry and fisheries; mining; and construction. The term Industrial Sector may also designate a business labeled as "industrial" by the North American Industry Classification System or by the energy provider on the basis of energy demand or annual usage exceeding some specified limit set by the energy provider. See **Commercial and Industrial** sector.

Internet: The worldwide, publicly accessible series of interconnected computer networks that transmit data by packet switching using the standard Internet Protocol.

Interruptible Load: Electric consumption subject to curtailment or interruption under tariffs or contracts that provide a rate discount or bill credit for agreeing to reduce load during system contingencies. In some instances, the demand reduction may be effected by action of the System Operator (remote tripping) after notice to the customer in accordance with contractual provisions.

Interval: The period of time for which advanced meters measure energy usage (and possibly other data). Increments are typically in minutes, and may consist of five-minute intervals, 15-minute intervals, or hourly intervals.

Interval Meter: An electric meter that measures energy use in increments of one hour or less.

Interval Usage: The amount of energy, measured in kWh, consumed during a period of time, typically five minutes, 15 minutes, or an hour.

Investor-Owned Electric Utility: A privately-owned electric utility whose stock is publicly traded. It is rate regulated and authorized to achieve an allowed rate of return.

Joint Action Agency: A body consisting of utility companies, municipalities who own public utilities, and/or municipalities who purchase energy from private utilities, which acts as a committee for making decisions regarding the acquisition and delivery of energy resources or related services.

Load as a Capacity Resource: Demand-side resources that commit to make pre-specified load reductions when system contingencies arise.

Load Serving Entity: Entities that provide electric service to end-users, wholesale customers, or both.

Mandatory Participation: Participation in the demand response program is required based on the customer's size or rate class. Customers are not offered the option of refusing to respond to requests for load reduction.

Maximum Demand: The highest level of demand in MWs as tracked by an entity, such as an hourly demand, 30-minute demand, 15-minute demand or 5-minute demand.

Maximum Demand of Customers: The highest level of total demand, in MWs, for customers participating in a demand response program, excluding any demand reduction that results from the program. The maximum noncoincident demand of the participating customers that would occur without the program.

Maximum Duration of Event: A specified maximum length of time a particular demand response event will continue, usually defined by 30-minute or hourly increments.

Megawatt (MW): One thousand kilowatts or one million watts of electric power.

Megawatt-hour (MWh): One thousand kilowatt-hours or one million watt-hours of electric energy.

Member Company: Member of a joint action agency or generation and transmission company that supplies wholesale electricity and energy services.

Minimum Payment Rate: The smallest amount of money, in dollars per megawatt-hour, that a program sponsor will pay a demand response program participant for reduced energy consumption.

Minimum Reduction: A level established by the demand response program sponsor as the least amount of demand reduction, in megawatts, a participant must achieve during a demand response event to be considered as participating in that event or to qualify for the demand response program.

Minimum Term: The shortest period of time that customers are obligated to participate in a demand response program.

Municipality: A village, town, city, county, or other political subdivision of a state.

NERC Regional Entity: One of the eight groups listed below (formerly known as Reliability Councils) organized within the major interconnections in the North American bulk power system. They work with the North American Electric Reliability Corporation to improve the reliability of the bulk power system. Florida Reliability Coordinating Council (FRCC), Midwest Reliability Organization (MRO), Northeast Power Coordinating Council (NPCC), Reliability*First* Corporation (RFC), SERC Reliability Corporation (SERC), Southwest Power Pool RE (SPP), Texas Reliability Entity (TRE), Western Electricity Coordinating Council (WECC). The states of Alaska and Hawaii are not within a NERC Regional Entity, but for purposes of this survey appear as a choice in NERC Regional Entity fields.

Non-Spinning Reserves: Demand-side resource that may not be immediately available, but may provide solutions for energy supply and demand imbalance after a delay of ten minutes or more.

Opt-In: A Time-Based Rate/Tariff or demand response program in which a customer will be enrolled only if the customer chooses to enroll.

Opt-Out: A Time-Based Rate/Tariff or demand response program in which a customer will be enrolled unless the customer chooses not to enroll; a program that is the default for a class of customers but that allows individual customers to choose an alternative rate/tariff or program.

Other (as shown in Q3, Q5 & Q6): Customers who are in a customer class that is not listed.

Other Demand Response Program/Tariff: A company or utility's service/product/compilation of all effective rate schedules, general terms and conditions and standard forms related to demand response/AMI services for customers that are not **Residential, Commercial and Industrial,** or **Other**.

Peak Time Rebate: Peak time rebates allow customers to earn a rebate by reducing energy use from a baseline during a specified number of hours on critical peak days. Like Critical Peak Pricing, the number of critical peak days is usually capped for a calendar year and is linked to conditions such as system reliability concerns or very high supply prices.

Penalties: Fines or reductions in payments that result when a demand response program participant fails to meet targeted reductions in power demand or chooses to not reduce consumption during a demand response event.

Potential Peak Reduction: The sum of the load reduction capabilities (measured in megawatts) of the demand response program participants, within the specified customer sector, whether reductions are made through the direct control of the utility system operator or by the participant in response to price signals or a utility request to curtail load. It reflects the demand reduction capability, as opposed to the actual peak reduction achieved by participants.

Power Marketers: Business entities, including energy service providers, which are engaged in buying and selling electricity, but which do not necessarily own generating or transmission facilities. Power marketers and energy service providers take ownership (title) of the electricity, unlike power brokers, who do not take title to electricity. Power marketers are involved in interstate commerce and must file with the FERC for authority to make wholesale sales. Energy service providers will not file with FERC but may file with the states if they undertake only retail transactions.

Program Type: The category of demand response arrangements between retail or wholesale entities and their retail or wholesale customers. Examples of these arrangements include*:* critical peak pricing, critical peak pricing with load control, direct load control, interruptible load, load as a capacity resource, regulation, non-spinning reserves, spinning reserves, demand bidding and buy-back, time of use pricing, real-time pricing, system peak response transmission tariff, peak time rebate, and emergency demand response, all of which are defined in this glossary.

Program End Date: A date specified when the demand response and/or time-based rate program is no longer in effect.

Program Start Date: A date specified when a demand response and/or time-based rate program began.

Public Utility District: Municipal corporations organized to provide electric service to both incorporated cities and towns and unincorporated rural areas.

Publicly Owned Electric Utility: Utilities operated by municipalities, political subdivisions, and state and federal power agencies (such as the Bonneville Power Administration and the Tennessee Valley Authority).

Realized Demand Reduction: The largest hourly demand reduction (in megawatts) that occurred when the demand response program was called, or that was attributable to the demand response program, during the 2009 calendar year.

Real Time Meters: Meters that measure energy as used, with built-in two-way communication capable of recording and transmitting instantaneous data.

Real Time Pricing: Rate and price structure in which the retail price for electricity typically fluctuates hourly or more often, to reflect changes in the wholesale price of electricity on either a day-ahead or hour-ahead basis.

Regulation Service: A type of Demand Response service in which a Demand Resource increases and decreases load in response to real-time signals from the system operator. Demand Resources providing Regulation Service are subject to dispatch continuously during a commitment period. This service is usually responsive to Automatic Generation Control (AGC) to provide normal regulating margin. Also known as regulation or regulating reserves, up-regulation and down-regulation.

Reliability: A measure of the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components.

Reliability Event: An event, such as the loss of a line or generator, or imbalance between supply and demand, which threatens the safe operation of the grid.

Reserve: A service in which demand resources are obligated to be available to provide demand reduction upon deployment by the system operator, based on reserve capacity requirements that are established to meet reliability standards.

Residential: The energy-consuming sector consisting of private households. Common uses of energy associated with this sector include space heating, water heating, air conditioning, lighting, refrigeration, cooking, and running a variety of other electric-powered devices. The residential sector excludes institutional living quarters. This sector excludes deliveries or sales to master-metered apartment buildings or homes on military bases (these buildings or homes are included in the commercial sector).

Response Time: The maximum time allowed in a demand response program for a program participant to react to the program sponsor's notification, in hours.

Retail: Sales covering electrical energy supplied for residential, commercial, industrial, and other (e.g., agricultural) end-use purposes. Electricity supplied at retail cannot be offered for resale.

Retail Customer: A purchaser of energy that consumes electricity for residential, commercial, or industrial use, or a variety of other end-uses.

Retail Electric Customer: See Retail Customer.

Rural Electric Cooperative: A member-owned electric utility company serving retail electricity customers. Electric cooperatives may be engaged in the generation, wholesale purchasing, transmission, and/or distribution of electric power to serve the demands of their members on a not-for-profit basis.

Specific Event Limits: The maximum number of times that a participant in a demand response program may be called to reduce energy consumption during a year.

Spinning/Responsive Reserves: Demand-side resource that is synchronized and ready to provide solutions for energy supply and demand imbalance within the first few minutes of an Emergency Event.

System Peak Response Transmission Tariff: The terms, conditions, and rates and/or prices for customers with interval meters who reduce load during peaks as a way of reducing transmission charges.

Tariff: A published volume of all effective rate schedules, terms and conditions under which a product or service will be supplied to customers.

Time-Based Rate/Tariff: A retail rate or Tariff in which customers are charged different prices for using electricity at different times during the day. Examples are time-of-use rates, real time pricing, hourly pricing, and critical peak pricing. Time-based rates do not include seasonal rates, inverted block, or declining block rates.

Time-of-Use: A rate where usage unit prices vary by time period, and where the time periods are typically longer than one hour within a 24-hour day. Time-of-use rates reflect the average cost of generating and delivering power during those time periods.

Transportation: An energy consuming sector that consists of electricity supplied and services rendered to railroads and inter-urban and street railways, for general railroad use including the propulsion of cars or locomotives, where such electricity is supplied under separate and distinct rate schedules. In this survey, transportation customers should be counted in the **Other** category.

Transportation Program/Tariff: A company or utility's service/product/compilation of all effective rate schedules, general terms and conditions and standard forms related to demand response/AMI services for transportation customers.

Type of Entity: The category of organization that best represents the energy market participant. The available options include: investor-owned utility, municipal utility, cooperative utility, state-owned utility, federally-owned utility, independent system operator, retail power marketer, wholesale power marketer, regional transmission operator, curtailment service provider, transmission, or other.

Voluntary: Customers have the option of participating or not participating. This would include opt-out programs where customers are automatically enrolled but are allowed to discontinue their participation.

Wholesale: Pertaining to a sale of electric energy for resale.

Wholesale Customer: An entity that purchases electric energy for resale.

APPENDIX D: 2010 FERC SURVEY METHOD

Background

The Energy Policy Act of 2005 (EPAct 2005) requires that the Federal Energy Regulatory Commission prepare and publish an annual report, by appropriate region, that assesses electricity demand response resources. Commission staff determined that a survey of a full set of private and public entities that provide electric power and demand response to customers would help fulfill the requirement.

In the first half of 2010 Commission Staff:

- Identified potential survey respondents ("the survey population"); and
- Developed a voluntary survey by revising previous demand response and advanced metering surveys, and developed an electronic survey form in Adobe® Reader® PDF format.

Beginning in May of 2010 Z, INC. and their subcontractor KEMA:

- Developed a sampling design based on the 2006 and 2008 FERC Demand Response and Advanced Metering Surveys;
- Implemented a custom survey processing system in MicroSoft Access, which linked to the FERC-provided PDF Survey;
- Reviewed the survey population and inactivated out of scope companies;
- Fielded the 2010 FERC Survey, collected the data, and followed-up with respondents where necessary; and
- Conducted data analysis of the survey responses.

Responses to the survey were requested from all 3,454 entities from all 50 states representing all aspects of the electricity delivery industry: investor owned utilities, municipally owned utilities, wholesale and retail power marketers, state and federal agencies, and (rural electric) cooperatives. The survey population was based on the universe of respondents identified by the Energy Information Administration (EIA) for their Form EIA-861. The FERC staff added three categories of respondents to the base set of EIA contacts – Regional Transmission Organizations (RTOs)/Independent System Operators (ISOs), curtailment service providers and transmission companies.

During the survey processing period it was determined that 96 entities were outside the scope of the survey or no longer in operation. These entities were inactivated in the survey database resulting in an active frame of 3,358. Out of this active group, 1,755 entities responded to the 2010 FERC Survey (a response rate of over 52 percent), a decrease from the 2008 response rates of 60 percent (for the advanced metering survey) and 55 percent (for the demand response survey).

Development of the FERC Survey and Sampling Design

The 2010 FERC Survey was conducted subject to Office of Management and Budget (OMB) authorization issued March 3, 2010 (OMB control number 1902-0251). As with past surveys, Commission staff fielded the survey on a voluntary rather than a mandatory basis. Commission staff designed the survey to collect the needed information using nine questions organized in three sections. One parent section contained questions one through seven, and two child sections covered retail and wholesale demand response programs, as described below:

<u>Parent record (only one record per respondent)</u>

Question 1: Entity name, ID number, company name and ownership type. Primary and supervisory contact information.

Question 2: Advanced meter and total meter counts by State and customer class.

Question 3: Number of retail customers and meters, by NERC region and customer class. (Respondents with demand response or time-based rates/tariffs skipped this question; those without such programs finished the survey at this question.)

Question 4: Number of retail customers that can access the amount and frequency of their electricity use measured at least hourly, by display type and by customer class.

Question 5: Plans for demand response programs and time-based rates/tariffs over the next five years, by number of programs, type of program, and potential peak reduction.

Question 6: NERC regions and States in which the respondent operates.

Question 7: For each NERC and State combination in Question 6, the number of retail customers, by customer class.

<u>Child 1 Record (repeated as needed)</u>

Question 8: Detailed retail demand response program information by NERC region, State, customer class and Program type.

<u>Child 2 Record (repeated as needed)</u>

Question 9: Detailed wholesale demand response program information by NERC region, State, and program type.

By shifting the detailed Demand Response Program information to the end of the survey, the burden on small utilities without demand response programs was lessened because they were asked to complete only Questions 1 through 3. Also, by having all the information relative to one demand response Program on one page (Child record), respondents could copy as many pages as required to cover all of their programs.

The content of the 2010 FERC Survey was similar to the content of the 2008 FERC Survey. The structure of the survey, however, was altered by combining two formerly separate surveys (FERC-727 and FERC-728) into a single survey, FERC-731, with both advanced metering and demand response topics. This was intended to simplify the respondent's task and increase the probability of response.

The Survey Population

To analyze the survey data and calculate statistics for this report, Commission staff reviewed the composition of the survey population and found that there were 3,454 organizations, as listed in Table D1.

The region definition used in the 2010 FERC Survey is that used by the North American Electric Reliability Corporation's eight regional entities.

Table D1. Survey population of the 2010 and 2008 FERC Surveys

2010 Group Name	2010 number	2008 Group Name	2008 number
Municipally Owned Utility	1,840	Municipal	1,845
Cooperatively Owned Utility	878	Cooperative	884
Investor Owned Utility	207	Investor Owned	223
Retail Power Marketer	128	Retail	107
Wholesale Power Marketer	46	Power Marketer	162
Political Subdivision	127	Public Utility District	126
Municipal Power Agency	21	Municipal Authority	21
		State	21
Federal and State	29	Federal	10
Regional Transmission Organization/Independent System Operator	7	Independent System Operator	8
Curtailment Service Provider	11	N/A	
Transmission	7	N/A	
Total Classified	3,301		
Unclassified	57	N/A	
Active Total	3,358		
Inactive	96		
Grand Total	3,454		3,407

FERC Survey Methodology

On June 1, 2010, the survey was distributed through a mass e-mailing. The email message included an introduction to the survey, directions and the glossary. The survey itself was attached to the e-mail, a departure from the on-line version used for the 2008 FERC Survey. The PDF document was programmed such that the respondents could respond directly on the PDF form. They then would e-mail the survey form to an e-mail account set up specifically for the collection of the surveys; another account was used for inquiries from respondents (DRSurvey@ferc.gov and DRSurvey-Help@ferc.gov).

Z, INC., in collaboration with the FERC staff, strove to maximize the response rate. A phone hotline was open daily between 9 am and 6 pm to assist respondents. The FERC staff also disseminated the survey through postal mail, to capture any respondents that might not have internet access or a functional e-mail account. Z, INC. sent out a reminder e-mail to all those who had not responded as of July 13, 2010, and made follow-up calls to all companies that were statistically significant (i.e. large companies and those selected for the sample), as well as all medium-sized companies, reaching more than 1,200 companies individually. Finally, FERC Chairman Jon Wellinghoff sent out a letter to all cooperating organizations, including members or representatives of the National Association of Regulatory Commissioners, American Public Power Association, Edison Electric Institute, and the National Rural Electric Cooperative Association, asking them to reach out to members and the industry to encourage submission of the survey.

As surveys came in, Z, INC. employed a rigorous system of verification and due diligence. Beyond the software used to collect the submissions to the e-mail account, Z, INC. also searched through the account looking for attachments that had not been included in the upload or other related problems. Anomalies and seemingly incorrect information received a flag, indicating the necessity for personal follow-up.

Efforts were made to ensure the optimal structure and processing of the incoming data. Z, INC. created a specialized database for the 2010 FERC Survey. This database included all available information for each firm selected as a potential respondent, an amalgamation of EIA-861 data and FERC's own records. A linked but separate portion of the database was then created to collect and track the incoming data from the survey participants. This allowed quick rectification of any updates or aberrations from past surveys or past information that might have been outdated or incorrect. This maintenance of the data allowed for a more efficient process overall, reducing the labor involved with cleaning data.

Working with the data

As discussed in Chapters 2 and 3, Commission staff used the 2010 FERC Survey to estimate advanced metering penetration rate and potential peak load reduction. The following discussion describes the analysis undertaken by Commission staff and Z Inc.'s subcontractor KEMA Inc., who was responsible for the analysis.

Advanced Metering

Commission staff developed estimates of the penetration rate of national and regional advanced metering, as required by EPAct 2005, at the national, regional, and state levels, as well as by load serving entity type. These estimates were to reflect all of the entities in the United States that own electricity meters for retail. The FERC survey population encompasses all such entities. As such, the primary data source of the estimates produced is the set of respondent data from the 2010 FERC Survey. Some entities did not respond to the 2010 FERC Survey, requiring statistical estimation of advanced metering penetration in their retail service territories so that the estimates account for the whole survey population.

The approach taken by KEMA was to make statistically informed imputations of the number of advanced and total meters for nonresponding entities using published information from the 2008 EIA-861 and 2008 FERC Survey. The EIA-861 file 2 contains customer counts at the entity level by customer class. These are highly correlated with total meter counts, a FERC Survey item. Other FERC Survey items – customer counts and advanced meters – have direct counterparts in the EIA-861. For the "Other" customer class (i.e., retail customers not classified as residential, commercial, or industrial), there is no comparable field in the EIA-861 to link to the 2010 FERC Survey. For this customer class, the 2008 FERC Survey was used as a source for the comparison survey field.

Trends in survey fields between survey years often reflect general growth or decline. For example, increases or decreases in total meter count tend to reflect population dynamics. Advanced meter count changes may reflect population dynamics as well, but also programmatic initiatives by the electricity retailer and other drivers. Simple imputation of 2008 EIA-861 or 2008 FERC Survey field values for missing values in the 2010 FERC Survey would not reflect the general trends. For example, suppose a utility did not respond to the 2010 FERC Survey but provided total advanced meters by sector in the 2008 EIA-861. An imputation procedure that simply substitutes that entity's 2008 EIA-861 advanced meter count into the 2010 FERC Survey would not reflect general growth trends.

To account for these trends, statistical models were used to create trend factors to apply to the 2008 data. The models were built using entities that had responded to both the 2010 FERC Survey and to either the 2008 FERC Survey or the EIA-861. The factors produced by these models could then be applied to the value for the 2008 comparison survey field for the 2010 FERC Survey nonrespondent. Separate models were fit for small, medium, and large entities for each survey field to reflect different growth among size classes of load-serving entities. Continuing the example above, instead of a straight substitution of the 2008 EIA-861 advanced meter count into the 2010 FERC Survey, the 2008 FERC Survey count would be multiplied by the modeled growth rate between 2008 EIA-861 and the 2010 FERC Survey. If the entity reported 8,000 advanced meters in 2008 and the modeled growth rate was twenty percent for other entities in its size class, the 2010 imputed value would be 8,000 x 1.2 = 9,600 advanced meters.

To restrict the effect of the modeled growth rates on the analysis, the sets of entities used in the statistical models were restricted to those whose 2010 counts were between half and double their 2008 counts – so if several entities had ten times the advanced meters in the 2010 FERC Survey as the 2008 FERC Survey, the modeled growth rates were not overly influenced by these massive individual increases. Additionally, the modeled growth factor was capped at a 10 percent change for meter and customer counts, which are not expected to vary significantly between comparison survey years. In most cases the modeled growth in meters and customers for the size classes between 2008 and 2010 FERC surveys was between one and five percent.

Tables and figures in this report labeled as having *estimated* count totals are comprised of the responding entity counts plus the imputed counts for the nonrespondents according to the method described above. No imputation was done for nonresponding entities with missing values in the comparison fields in the 2008 FERC Survey.

Alternative approaches were considered, such as applying weights to the meter and customer data submitted by 2010 FERC Survey respondents to account for nonrespondents. While applying nonresponse weights is common in survey estimation, they can lead to volatile estimates for subgroups of the survey population with high levels of nonresponse. For example, if fifty municipal utilities in a state were asked to complete the FERC Survey and only fifteen responded, the weighted estimate assumes that the number of residential advanced meters with respect to a size variable, which may be total customers (as reported in the 2008 EIA-861), is the same for the 15 respondents as the 35 nonrespondents. Commission staff believes that entities who respond to the FERC Survey may have higher advanced metering penetration than those who do not respond, which would violate the key assumption of nonresponse weighting. If all of the meters the fifteen municipal utilities own are advanced, assuming the same of the 35 nonresponding municipal utilities in the state may not be appropriate.

The statistical regression model-adjusted imputation approach controls against self-selection bias by having past entity-level values—adjusted for growth trends—account for the meters and customers of nonresponding entities. Since many of the past entity-level values come from the mandatory EIA-861 survey, they are less subject to self-selection bias than the responses to the voluntary FERC Survey. Further, the response rates of the random samples are similar to the general response rates, as shown in Table H2, suggesting that self-selection is not significant.

There is, however, the chance that the regression coefficient is biased towards the entities used in the regression, so the coefficients by design are limited to change the meter and customer counts from their respective 2008 FERC Survey counts by no more than 10 percent.

Demand Response

The general extrapolation approach for the demand response section of the 2010 FERC Survey was consistent with the approach used for the meter and customer counts in the advanced metering section, as described above. The entity-level comparison survey field values come from either the 2008 FERC Survey or EIA-861. The 2008 EIA-861 contains customer class-level potential and actual peak load reduction from both time-based and incentive-based programs. The 2008 FERC Survey was used, as in the advanced metering section, for the "other" customer class balance group, and for customer counts and peak load reduction by specific program type.

As with the meter and customer counts, the demand response survey item regressions were fit on 2008-2010 paired entity-level survey data, and resulted in factors yielding between half and double the 2008 values. Unlike the regression results for the total number of meters and total number of customers, the factors for demand response fields were not restricted to a maximum 10 percent statistical model-based adjustment over the 2008 values. The cap was not applied to demand response fields because, based on research, it is reasonable for the potential for peak load reduction to have increased by more than 10 percent between survey years.

More details on the imputation procedure used to account for nonresponding entities can be found in Appendix H.

Table D2. Assigned demand response program types for RTO/ISO programs

RTO / ISO	Program Acronym	Program Name	Service Type	FERC Staff-assigned Program Type
CAISO	PLP	Participating Load Program	Energy	Demand Bidding and Buyback
CAISO	PLP	Participating Load Program	Reserve	Demand Bidding and Buyback
ERCOT	EILS	Emergency Interruptible Load Service	Capacity	Emergency Demand Response
ERCOT	LaaR / RRS / UFR	Loads Acting as a Resource providing Responsive Reserve Service -- Under Frequency Relay Type	Reserve	Spinning Reserves
ERCOT	LaaR / RRS / CLR	Loads Acting as a Resource providing Responsive Reserve Service -- Controllable Load Resource Type	Reserve	Spinning Reserves
ERCOT	LaaR / NSRS /	Loads Acting as a Resource providing Non-Spinning Reserve Service	Reserve	Non-spinning Reserves
ERCOT	CLR	Controllable Load Resources providing Regulation Service	Regulation	Regulation
ISO-NE	RTDRP	Real Time Demand Response Program [Capacity Component]	Capacity	Emergency Demand Response
ISO-NE	RTDRP	Real Time Demand Response Program [Energy Component]	Energy	Emergency Demand Response
ISO-NE	DALRP-RTDR	Day-Ahead Load Response Program for RTDRP	Energy	Demand Bidding and Buyback
ISO-NE	DALRP- RTPR	Day-Ahead Load Response Program for RTPR	Energy	Demand Bidding and Buyback
ISO-NE	DRR	Demand Response Reserves Pilot	Reserve	Non-spinning Reserves
ISO-NE	RTPR	Real Time Price Response Program	Energy	Demand Bidding and Buyback
ISO-NE	RTDR	Real Time Demand Response Resource	Capacity	Emergency Demand Response
ISO-NE	OP and SP	FCM: On-Peak, Seasonal Peak Resources	Capacity	Load as a Capacity Resource
ISO-NE	RTEG	Real Time Emergency Generation Resource	Capacity	Emergency Demand Response
MISO	EDR	Emergency Demand Response	Energy	Emergency Demand Response
MISO	DRR-I	Demand Response Resource Type I	Energy	Spinning Reserves
MISO	DRR-I	Demand Response Resource Type-I	Reserve	Spinning Reserves
MISO	DRR-II	Demand Response Resource Type II	Energy	Regulation
MISO	DRR-II	Demand Response Resource Type-II	Reserve	Regulation
MISO	DRR-II	Demand Response Resource Type-II	Regulation	Regulation
MISO	LMR	Load Modifying Resource	Capacity	Load as a Capacity Resource
NYISO	DADRP	Day-Ahead Demand Response Program	Energy	Demand Bidding and Buyback
NYISO	DSASP	Demand Side Ancillary Services Program	Reserve	Spinning Reserves
NYISO	DSASP	Demand Side Ancillary Services Program	Reserve	Non-spinning Reserves
NYISO	DSASP	Demand Side Ancillary Services Program	Regulation	Regulation
NYISO	EDRP	Emergency Demand Response Program	Energy	Emergency Demand Response

RTO / ISO	Program Acronym	Program Name	Service Type	FERC Staff-assigned Program Type
NYISO	SCR	Installed Capacity Special Case Resources (Energy Component)	Energy	Load as a Capacity Resource
NYISO	SCR	Installed Capacity Special Case Resources (Capacity Component)	Capacity	Load as a Capacity Resource
PJM	Economic	Economic Load Response	Energy	Demand Bidding and Buyback
PJM	Economic	Economic Load Response	Reserve	Spinning Reserves
PJM	Economic	Economic Load Response	Reserve	Non-spinning Reserves
PJM	Economic	Economic Load Response	Regulation	Regulation
PJM	Emergency (Energy Only)	Emergency Load Response - Energy Only	Energy	Emergency Demand Response
PJM	Emergency	Full Emergency Load Response (Capacity Component)	Capacity	Load as a Capacity Resource
PJM	Emergency	Full Emergency Load Response (Energy Component)	Energy	Load as a Capacity Resource
SPP	VDDR	Variable Dispatch Demand Response	Energy	Emergency Demand Response

Sources: ISO/RTO Council, *North American Wholesale Electricity Demand Response 2009 Comparison (http://www.isorto.org/atf/cf/%7B5B4E85C6-7EAC-40A0-8DC3-003829518EBD%7D/IRC%20DR%20M&V%20Standards%20Implementation%20Comparison%20(2009-04-28).xls);* FERC staff.

APPENDIX E: FERC SURVEY RESPONDENTS

Appendix E lists the entities that responded to the 2010 FERC Survey, organized by entity type.

Cooperatively Owned Utilities

A & N Electric Cooperative	MD,VA
Adams Electric Cooperative	IL
Adams Electric Cooperative, Inc.	PA
Adams Rural Electric Cooperative, Inc.	OH
Adams-Columbia Electric Cooperative	WI
Agralite Electric Cooperative	MN
Aiken Electric Cooperative, Inc.	SC
Albemarle Electric Member Corp.	NC
Alder Mutual Light Co., Inc.	WA
Alfalfa Electric Cooperative, Inc.	KS,OK
Alger-Delta Cooperative Electric Association	MI
Allegheny Electric Cooperative, Inc.	PA
Amicalola Electric Membership Corp	GA
Anza Electric Cooperative, Inc.	CA
Appalachian Electric Cooperative	TN
Arizona Electric Power Cooperative, Inc.	AZ
Arkansas Electric Cooperative Corporation	AR
Arkansas Valley Electric Cooperative Corporation	AR,OK
Arrowhead Electric Cooperative, Inc.	MN
Ashley-Chicot Electric Cooperative, Incorporated	AR
Atchison-Holt Electric Cooperative	IA,MO
Bailey County Electric Cooperative Association	TX
Bandera Electric Cooperative, Inc.	TX
BARC Electric Cooperative	VA
Barrow Utilities & Electric Coop., Inc.	AK
Barry Electric Cooperative	MO
Bartlett Electric Cooperative	TX
Basin Electric Power Cooperative	ND,SD
Bayfield Electric Cooperative	MI,WI
Beartooth Electric Cooperative, Inc.	MT,WY
Beauregard Electric Coop., Inc.	LA
Bedford Rural Electric Cooperative, Inc.	PA
Beltrami Electric Cooperative, Inc.	MN
Benton Rural Electric Association	WA
Big Country Electric Cooperative, Inc.	TX
Big Flat Electric Co-op, Inc.	MT
Big Horn Rural Electric MT,	WY
Big Sandy Rural Electric Cooperative Corporation	KY
Black Hills Electric Cooperative, Inc	SD
Black River Electric Cooperative	MO
Black River Electric Cooperative, Inc.	SC
Black Warrior Electric Membership Corporation	AL
Blue Grass Energy Cooperative Corporation	KY
Blue Ridge Electric Membership Corporation	NC
Bluebonnet Electric Cooperative, Inc.	TX
Bluestem Electric Cooperative Inc.	KS
Boone County Rural EMC	IN
Boone Electric Cooperative	MO
Brazos Electric Power Cooperative, Inc.	TX
Broad River Electric Cooperative, Inc.	NC,SC
Brown County Rural Electrical Assn.	MN
Brown-Atchison Electric Cooperative Association, Inc.	KS
Brunswick Electric Membership Corporation	NC
Buckeye Power, Inc.	OH
Buckeye Rural Electric Cooperative	OH
Burt County Public Power District	NE
Butler County Rural Electric Cooperative	IA
Butte Electric Cooperative, Inc.	SD
C & L Electric Cooperative Corporation	AR
Calhoun County Electric Cooperative Association	IA
Callaway Electric Cooperative	MO
Cam Wal Electric Cooperative, Inc	SD
Canadian Valley Electric Cooperative	OK
Caney Fork Electric Cooperative, Inc.	TN
Capital Electric Cooperative, Inc.	ND
Carbon Power & Light Inc	WY
Carroll County REMC	IN
Carroll Electric Cooperative Corporation	AR,MO
Carroll Electric Cooperative, Inc	OH
Carteret-Craven Electric Membership Corporation	NC
Cass County Electric Cooperative	ND
Cavalier Rural Electric Coop.,Inc.	ND
Cedar-Knox Public Power District	NE
Central Alabama Electric Cooperative	AL
Central Electric Co-Op	OR
Central Electric Cooperative	SD
Central Electric Cooperative, Inc.	PA
Central Electric Membership Corporation	NC
Central Electric Power Association	MS
Central Electric Power Cooperative	MO
Central Electric Power Cooperative, Inc.	SC
Central Florida Electric Cooperative, Inc.	FL
Central Georgia Electric Membership Corp	GA
Central Iowa Power Cooperative	IA
Central Virginia Electric Cooperative	VA
Chariton Valley Electric Cooperative, Inc.	IA
Chickasaw Electric Cooperative	TN
Choptank Electric Cooperative, Inc.	MD
Chugach Electric Association, Inc.	AK
Cimarron Electric Cooperative	OK
Citizens Electric Corporation	MO
Claiborne Electric Cooperative, Inc.	LA
Clark County Rural E M C	IN
Clarke Electric Cooperative, Inc.	IA
Claverack Rural Electric Cooperative, Inc.	PA
Clay County Electric Cooperative Corporation	AR
Clay Electric Cooperative, Inc.	FL
Clay-Union Electric Corporation	SD
Clearwater-Polk Electric Cooperative, Inc.	MN
CMS Electric Cooperative, Inc.	KS
Coahoma Electric Power Association	MS
Coast Electric Power Association	MS
Coastal Electric Membership Corporation	GA
Codington-Clark Electric Cooperative, Inc	SD
Colquitt Electric Membership Corporation	GA

Cooperatively Owned Utilities (Continued)

Columbia Basin Electric Cooperative, Inc.	OR
Columbus Electric Cooperative, Inc.	AR,NM
Comanche Co Electric Cooperative Assn Inc	TX
Community Electric Cooperative	VA
Co-Mo Electric Cooperative, Inc.	MO
Concordia Electric Cooperative, Inc.	LA
Connexus Energy	MN
Consolidated Electric Cooperative	MO
Consumers Energy Cooperative	IA
Consumers Power Inc.	OR
Continental Divide Electric Cooperative, Inc.	NM
Cookson Hills Electric Cooperative, Inc.	OK
Cooperative Light and Power Association	MN
Coos-Curry Electric Cooperative, Inc.	OR
Copper Valley Electric Association, Inc.	AK
Corn Belt Energy Corporation	IL
Covington Electric Cooperative, Inc.	AL
Coweta-Fayette EMC	GA
Craig-Botetourt Electric Cooperative	VA,WV
Craighead Electric Cooperative Corporation	AR
Crawford Electric Cooperative, Inc	MO
Crow Wing Cooperative Power & Light Company	MN
Cuivre River Electric Cooperative, Inc	MO
Cullman Electric Cooperative	AL
Cumberland Electric Membership Corporation	TN
Dairyland Power Cooperative	IA,MN,WI
Dakota Electric Association	MN
Daviess-Martin County	REMC IN
Deep East Texas Electric Cooperative, Inc.	TX
Delaware Electric Cooperative, Inc.	DE
Delta Electric Power Association	MS
Denton County Electric Cooperative, Inc.	TX
Deseret Generation & Transmission Co-operative	AZ,CO,NV,UT,WY
Diverse Power Incorporated	AL,GA
Dixie Electric Cooperative	AL
Dixie Electric Membership Corporation	LA
Dixie Electric Power Association	MS
Dixie Escalante Rural Electric Association, Inc.	AZ,UT
Doniphan Electric Cooperative Assn, Inc.	KS
Douglas Electric Cooperative, Inc	SD
Douglas Electric Cooperative, Inc.	OR
Dubois Rural Electric Cooperative, Inc.	IN
Duck River Electric Membership Corporation	TN
Duncan Valley Electric Cooperative	AZ,NM
Dunn County Electric Cooperative	WI
East central Oklahoma Electric Cooperative, Inc.	OK
East Mississippi Electric Power Association	MS
East River Electric Power Cooperative, Inc.	MN,SD
East-Central Iowa Rural Electric Cooperative	IA
Eastern Maine Electric Cooperative, Inc.	ME
Eastside Power Authority	CA
Edgecombe-Martin County Electric Membership Corp.	NC
Edisto Electric Cooperative, Inc.	SC
Egyptian Electric Cooperative Association	IL

Elmhurst Mutual Power & Light	WA
EnergyUnited Electric Membership Corporation	NC
Escambia River Electric Cooperative	FL
Excelsior Electric Membership Corporation (EMC)	GA
Fairfield Electric Cooperative, Inc.	SC
Fall River Rural Electric Cooperative, INC	ID,MT,WY
Fannin County Electric Cooperative, Inc.	TX
Farmers Electric Company, Ltd	ID
Farmers' Electric Coop, Inc of New Mexico	NM
Farmers Electric Cooperative	TX
Farmers Electric Cooperative Corporation	AR
Farmers Electric Cooperative, Inc.	IA
Farmers' Electric Cooperative, Inc.	MO
Farmers Mutual Electric Company	IL
Farmers Rural Electric Cooperative Corporation	KY
Federated Rural Electric Association	MN
FEM Electric Association, Inc	SD
Fergus Electric Cooperative, Inc.	MT
First Electric Cooperative Corporation	AR
Flathead Electric Cooperative, Inc.	MT
Flint Electric Membership Corporation	GA
Flint Hills Rural ECA, Inc	KS
Florida Keys Electric Cooperative Association, Inc.	FL
Forked Deer Electric Cooperative	TN
Four County Electric Membership Corporation	NC
Franklin Electric Cooperative	AL
Franklin Rural Electric Cooperative	IA
Fulton County Rural Electric Membership Corporation	IN
Garkane Energy Cooperative, Inc	AZ,UT
Garland Light and Power Co.	WY
Gascosage Electric Cooperative	MO
Georgia Transmission Corporation	GA
Gibson Electric Membership Corporation	TN
Glacier Electric Cooperative, Inc.	MT
Golden Spread Electric Cooperative, Inc.	TX
Goodhue County Cooperative Electric Association	MN
Graham County Electric Cooperative, Inc.	AZ
Grand Valley Rural Power Lines, Inc.	CO
Grayson-Collin Electric Cooperative, Inc.	TX
Great River Energy	MN
Greenbelt Electric Cooperative, Inc.	TX
Grundy Electric Cooperative, Inc.	MO
Guadalupe Valley Electric Cooperative, Inc.	TX
Guernsey-Muskingum Electric Cooperative, Inc.	OH
Gulf Coast Electric Cooperative, Inc.	FL
Gunnison County Electric Association, Inc.	CO
Guthrie County Rural Electric Cooperative	IA
Habersham Electric Membership Corporation	GA
Hancock County Rural Electric Membership Corp.	IN
Hancock Wood Electric Cooperative, Inc	OH
Harrison Rural Electrification Association, Inc.	WV
Hart Electric Membership Corporation	GA

Cooperatively Owned Utilities (Continued)

Haywood Electric Membership Corporation	GA,NC,SC
H-D Electric Cooperative, Inc	MN,SD
Heart of Texas Electric Cooperative	TX
Heartland Rural Electric Cooperative, Inc.	KS
Hendricks County Rural Electric Membership Coop	IN
Henry County Rural Electric Membership Corporation	IN
Hickman-Fulton Co. Rural Electric Cooperative Corp.	KY
High Plains Power Inc.	WY
Highline Electric Association	CO,NE
HILCO Electric Cooperative, Inc.	TX
Hill County Electric Cooperative, Inc.	MT
Holmes-Wayne Electric Cooperative, Inc.	OH
Holston Electric Cooperative	TN
Holy Cross Energy	CO
Horry Electric Cooperative, Inc.	SC
Houston County Electric Cooperative, Inc.	TX
Howell-Oregon Electric Cooperative	MO
Humboldt County Rural Electric Cooperative	IA
Idaho Cnty L&P Coop Assn, Inc.	ID
Illinois Rural Electric Cooperative	IL
Indian Electric Cooperative	OK
Inside Passage Electric Coop	AK
Intercounty Electric Cooperative Association	MO
Inter-county Energy Cooperative Cooperation	KY
Irwin Electric Membership Corporation	GA
Itasca-Mantrap Cooperative Electrical Association	MN
J-A-C Electric Cooperative Inc.	TX
Jackson Electric Cooperative	WI
Jackson Electric Cooperative, Inc	TX
Jackson Electric Membership Corporation	GA
Jackson Energy Coop Corp	KY
Jackson Purchase Energy Corporation	KY
Jasper County Rural Electric Membership Corporation	IN
Jasper Newton Electric Cooperative, Inc.	TX
Jemez Mountains Electric Cooperative, Inc.	NM
Jo-Carroll Energy, Inc.(NFP)	IL
Joe Wheeler Electric Membership Corporation	AL
Johnson County REMC	IN
Jones-Onslow Electric Membership Corporation	NC
Jump River Electric Cooperative, Inc.	WI
KAMO Electric Cooperative, Inc	MO,OK
Kandiyohi Power Cooperative	MN
Kankakee Valley Rural Electric Membership Corporation	IN
Kansas Electric Power Cooperative, Inc.	KS
Karnes Electric Cooperative Inc.	TX
Kauai Island Utility Cooperative	HI
Kay Electric Cooperative	OK
KC Electric Association, Inc.	CO
KEM Electric Cooperative, Inc.	ND
Kiamichi Electric Cooperative, Inc	OK
Kingsbury Electric Cooperative, Inc.	SD
Kodiak Electric Association, Inc.	AK
Kootenai Electric Cooperative, Inc	ID
Kosciusko REMC	IN
Kotzebue Electric Assoc.	AK
Kwethluk Inc.	AK
La Plata Electric Association, Inc.	CO
Laclede Electric Cooperative	MO
Lacreek Electric Association, Inc.	NE,SD
LaGrange County Rural Electric Membership Corp.	IN
Lake Region Electric Cooperative	MN
Lakeview Light & Power	WA
Lamar County Electric Cooperative Association	TX
Lamb County Electric Cooperative	TX
Lane-Scott Electric Cooperative, Inc	KS
Lea County Electric Cooperative Inc.	NM,TX
Lee County Electric Cooperative, Incorporated	FL
Licking Valley RECC	KY
Lighthouse Electric Cooperative, Inc.	TX
Linn County Rural Electric Cooperative Assoc.	IA
Little Ocmulgee El Member Corp	GA
Logan County Cooperative Power & Light Assoc Inc	OH
Lumbee River Electric Membership Corporation	NC
Lynches River Electric Cooperative, Inc	SC
Lyntegar Electric Cooperative, Inc.	TX
Lyon Rural Electric Cooperative	IA
Lyon-Lincoln Electric Cooperative, Inc.	MN
M & A Electric Power Cooperative	MO
Macon Electric Cooperative	MO
Magic Valley Electric Cooperative, Inc.	TX
Magnolia Electric Power Association	MS
Maquoketa Valley REC	IA
Marshall County Rural Electric Membership Corp.	IN
Marshall-DeKalb Electric Cooperative	AL
McCone Electric Co-op., Inc.	MT
McDonough Power Coop	IL
McKenzie Electric Cooperative, Inc.	ND
McLean Electric Cooperative, INC	ND
McLeod Cooperative Power Association	MN
Meade County RECC	KY
Mecklenburg Electric Cooperative	NC,VA
Medina Electric Cooperative, Inc.	TX
Meeker Cooperative Light & Power Association	MN
Menard Electric Cooperative	IL
Mid South Synergy	TX
Middle Kuskokwim Electric Cooperative, Inc.	AK
Mid-Ohio Energy Cooperative, Inc.	OH
Midwest Electric Inc	OH
Midwest Energy Cooperative	IN,MI,OH
Midwest Energy, Inc.	KS
Mid-Yellowstone Electric Cooperative, Inc.	MT
Mille Lacs Energy Cooperative	MN
Minnesota Valley Electric Cooperative	MN
Minnkota Power Cooperative, Inc.	ND
Mississippi County Electric Cooperative , Inc.	AR
Missouri Rural Electric Cooperative	MO
MJM Electric Cooperative, Inc.	IL

Cooperatively Owned Utilities (Continued)

Modern Electric Water Company	WA
Monroe County Electric Co-Operative, Inc.	IL
Moon Lake Electric Assn. Inc.	CO,UT
Mora San Miguel Electric Cooperative Inc.	NM
Moreau-Grand Electric Cooperative, Inc.	SD
Mor-Gran-Sou Electric Cooperative, Inc.	ND
Mountain Electric Cooperative, Inc.	TN
Mountain Parks Electric, Inc.	CO
Mountain View Electric Association, Inc.	CO
Natchez Trace Electric Power Association	MS
Navarro County Electric Cooperative, Inc.	TX
Navopache Electric Cooperative, Inc.	AZ,NM
NC Electric Membership Corp	NC
Nemaha-Marshall Electric	KS
Nespelem Valley Electric Cooperative, Inc.	WA
New Enterprise Rural Electric Cooperative, Inc.	PA
New Hampshire Electric Cooperative, Inc	NH
Newberry Electric Cooperative, Inc.	SC
New-Mac Electric Cooperative, Inc.	MO
Newton County Rural Electric Membership Corporation	IN
Niobrara Electric Association	NE,SD,WY
Nishnabotina Valley Rural Electric Cooperative	IA
Noble County REMC	IN
Nobles Cooperative Electric	IA,MN
North Alabama Electric Cooperative	AL
North Arkansas Electric Cooperative, Incorporated	AR
North Central Mo. Electric Coop	MO
North Georgia Electric Membership Corporation	GA
North Itasca Electric Cooperative Inc.	MN
North Plains Electric Cooperative, Inc.	TX
North Star Electric Cooperative, Inc.	MN
North Western Electric Cooperative, Inc.	OH
Northeast Missouri Electric Power Cooperative	MD
Northeast Oklahoma Electric Cooperative	OK
Northeastern REMC	IN
Northern Lights, Inc.	ID,MT,WA
Northern Neck Electric Cooperative	VA
Northern Rio Arriba Electric Coop., Inc.	NM
Northern Virginia Electric Cooperative	VA
Northwestern Rural Electric Coop Association, Inc.	PA
NorVal Electric Cooperative	MT
Nueces Electric Cooperative, Inc.	TX
Oahe Electric Coop Inc.	SD
Ocmulgee Electric Membership Corporation	GA
Oglethorpe Power Corporation	GA
Okanogan County Electric Cooperative Inc	WA
Okefenoke Rural El Member Corp	FL,GA
Oklahoma Electric Cooperative	OK
Old Dominion Electric Cooperative	VA
Oneida-Madison Electric Cooperative Inc	NY
Ontonagon County Rural Electrification Assoc.	MI
Orcas Power and Light Cooperative	WA
Oregon Trail Electric Consumers Cooperative, Inc.	OR
Osage Valley Electric Cooperative Ass'n	MO
Osceola Electric Cooperative, Inc.	IA
Otero County Electric Cooperative, Inc.	NM
Otsego Electric Cooperative, Inc.	NY
Ouachita Electric Cooperative	AR
Ozark Border Electric Cooperative	MO
Ozark Electric Cooperative, Inc.	MO
Ozarks Electric Cooperative Corporation	AR,OK
Pacific Northwest Generating Cooperative	OR
Palmetto Electric Cooperative, Inc.	SC
Panhandle Rural Electric Membership Association	NE
Parke County Rural Electric Membership Corporation	IN
Paulding Putnam Electric Cooperative, Inc.	IN,OH
Pea River Electric Coop	AL
Peace River Electric Cooperative, Inc.	FL
Pedernales Electric Cooperative, Inc.	TX
Pee Dee Electric Cooperative, Inc.	SC
Pee Dee Electric Membership Corp.	NC
Pemiscot-Dunklin Electric Cooperative, Inc.	MO
Peninsula Light Company	WA
Pickwick Electric Cooperative	TN
Piedmont Electric Membership Corporation	NC
Pioneer Rural Electric Cooperative	OH
Pitt and Greene Electric Membership Corporation	NC
Planters Electric Membership Corporation	GA
Platte-Clay Electric Cooperative, Inc.	MO
Plumas-Sierra Rural Electric Cooperative	CA,NV
Pointe Coupee Electric Membership Corporation	LA
Pontotoc Electric Power Association	MS
Poudre Valley Rural Electric Association	CO
Powder River Energy Corporation	MT,WY
Powell Valley Electric Cooperative	TN
Power Resources Cooperative	OR
Prairie Land Electric Cooperative, Inc.	KS
Prentiss County Electric Power Association	MS
Price Electric Cooperative	WI
Prince George Electric Cooperative	VA
Radiant Electric Cooperative, Inc.	KS
Raft River Rural Electric Cooperative, Inc.	ID, NV, UT
Ralls County Electric Cooperative	MO
Randolph Electric Membership Corporation	NC
Rappahannock Electric Cooperative	VA
Ravalli County Electric Co-op	MT
Rayburn Country Electric Cooperative, Inc.	TX
REA Energy Cooperative, Inc.	PA
Red Lake Electric Cooperative, Inc.	MN
Red River Valley Cooperative Power Association	MN
Red River Valley Rural Electric Association	OK
Renville-Sibley Cooperative Power Association	MN
Rich Mountain Electric Cooperative, Inc.	AR
Rita Blanca Electric Coop, Inc.	TX
Rolling Hills Electric Cooperative, Inc.	KS
Rosebud Electric Coop Inc.	SD
Roughrider Electric Cooperative, Inc.	ND

Cooperatively Owned Utilities (Continued)

Rural Electric Cooperative, Inc.	OK
Rusk County Electric Cooperative, Inc.	TX
Rutherford Electric Membership Corporation	NC
Sac Osage Electric Coop, Inc.	MO
Salem Electric	OR
Salmon River Electric Cooperative Inc.	ID
Salt River Electric Coop Corp	KY
Sam Houston Electric Cooperative, Inc	TX
San Bernard Electric Cooperative, Inc.	TX
San Luis Valley REC	CO
San Miguel Electric Cooperative, Inc.	TX
San Miguel Power Association Inc.	CO
San Patricio Electric Cooperative, Inc.	TX
Sangre De Cristo Electric Association, Inc	CO
Santee Electric Cooperative Inc.	SC
Satilla Rural Electric Membership Corporation	GA
Sawnee Electric Membership Corporation	GA
Se-Ma-No Electric Cooperative	MO
Seminole Electric Cooperative, Inc.	FL
SEMO Electric Cooperative	MO
Shelby Electric Cooperative	IL
Shelby Energy Cooperative Inc.	KY
Shenandoah Valley Electric Cooperative	VA,WV
Sheridan Electric Co-op., Inc.	MT
Sho-Me Power Electric Cooperative	MO
Sierra Electric Cooperative, Inc.	NM
Singing River Electric Power Association	AL,MS
Sioux Valley Southwestern Electric Cooperative, In	MN,SD
Slash Pine Electric Membership Corporation	GA
Slope Electric Cooperative, Inc	ND
Smarr EMC	GA
Snapping Shoals Electric Membership Corporation	GA
Somerset Rural Electric Cooperative, Inc.	PA
South Central Arkansas Electric Cooperative, Inc.	AR
South Central Indiana REMC	IN
South Central Power Company	OH
South Kentucky Rural Electric Cooperative Corp	KY,TN
South Louisiana Electric Cooperative Association	LA
South Mississippi Electric Power Association	MS
South Plains Electric Cooperative	TX
South Side Electric, Inc.	ID
Southeast Colorado Power Association	CO
Southeastern Electric Cooperative, Inc.	OK
SouthEastern Illinois Electric Cooperative, Inc.	IL
Southern Indiana REC, Inc.	IN
Southern Iowa Electric Cooperative, Inc.	IA
Southern Maryland Electric Cooperative, Inc.	MD
Southern Pine Electric Power Association	MS
Southside Electric Cooperative, Crewe,Virginia	VA
Southwest Arkansas Electric Cooperative Corporation	AR
Southwest Electric Cooperative	MO
Southwest Louisiana Electric Membership Corp	LA
Southwest Rural Electric Association	OK,TX
Southwest Tennessee Electric Membership Corporation	TN
Southwest Texas Electric Cooperative, Inc	TX
Southwestern Electric Cooperative, Inc.	CO,NM,OK,TX
Square Butte Electric Cooperative	ND
Steele-Waseca Cooperative Electric	MN
Steuben Rural Electric Cooperative, Inc.	NY
Sullivan County Rural Electric Cooperative, Inc.	PA
Sumner-Cowley Electric Cooperative, Inc.	KS
Sumter Electric Cooperative, Inc.	FL
Sumter Electric Membership Corporation	GA
Sun River Electric Cooperative, Inc.	MT
Surprise Valley Electrification Corp.	CA,NV,OR
Sussex Rural Electric Cooperative, Inc.	NJ
Suwannee Valley Electric Cooperative, Inc.	FL
Swisher Electric Cooperative, Inc	TX
Tallahatchie Valley Electric Power Association	MS
Tallpoosa River Electric Cooperative, Inc.	AL
Talquin Electric Cooperative, Inc,	FL
Taylor County Rural Electric Cooperative Corporation	KY
Taylor Electric Cooperative	WI
Taylor Electric Cooperative, Inc.	TX
The Caney Valley Electric Cooperative Assn., Inc.	KS
The Delaware County Electric Cooperative, Inc.	NY
The Frontier Power Company	OH
The Midwest Electric Cooperative Corporation	NE
Three Notch Electric Membership Corporation	GA
Tipmont Rural Electric Member Corp	IN
Traverse Electric Cooperative, Inc.	MN,ND,SD
Tri County Electric Cooperative Association	MO
Tri-County Electric Cooperative, Inc	TX
Tri-County Electric Cooperative, Inc.	CO,KS,NM,OK,TX
Tri-County Electric Membership Corporation	NC
Tri-County Rural Electric Cooperative, Inc.	PA
Trinity Valley Electric Cooperative, Inc.	TX
Tuntutuliak Community Services Association	AK
Twin County Electric Power Association	MS
Twin Valley Electric Cooperative	KS
Unalakleet Valley Electric Cooperative	AK
Union County Electric Cooperative, Inc.	SD
Union Electric Membership Corporation	NC
United Electric Coop	ID
United Electric Coop Services	TX
United Electric Cooperative, Inc.	IA,MO
United Power, Inc	CO
Upper Cumberland Electric Membership Corporation	TN
Upshur Rural Electric Cooperative Corp	TX
Valley Electric Association	CA,NV
Valley Electric Membership Corporation	LA
Valley Rural Electric Cooperative, Inc.	PA
Verdigris Valley Electric Cooperative, Inc	OK
Verendrye Electric Cooperative, Inc.	ND
Vermont Electric Cooperative, Inc.	VT
Vigilante Electric Cooperative, Inc.	ID,MT
Wabash County REMC	IN
Wabash Valley Power Assn, Inc.	IL,IN,MI,MO
Walton Electric Membership Corporation	GA
Warren Electric Cooperative, Inc.	PA
Wasco Electric Cooperative, Inc.	OR
Washington Electric Cooperative Inc	VT

Cooperatively Owned Utilities (Continued)

Washington Electric Cooperative, Inc.	OH
Washington Electric Membership Corporation	GA
Washington-St.Tammany Electric Cooperative, Inc.	LA,MS
Wayne-White Counties Electric Cooperative	IL
Webster Electric Cooperative	MO
West Central Electric Cooperative, Inc	MO
West River Electric Association, Inc.	SD
Western Cooperative Electric Association, Inc.	KS
Western Farmers Electric Cooperative	OK
Western Illinois Electric Coop	IL
Western Indiana Energy REMC	IN
Western Iowa Power Cooperative	IA
Wheatland Electric Cooperative, Inc.	CO,KS
White County REMC	IN
White River Valley Electric Cooperative	MO
Whitewater Valley REMC	IN
Willwood Light & Power Co.	WY
Wiregrass Electric Cooperative, Inc.	AL
Wise Electric Coop Inc.	TX
Withlacoochee River Electric Cooperative, Inc.	FL
Woodruff Electric Cooperative Corporation	AR
Wright-Hennepin Cooperative Electric Association	MN
Wyrulec Company	NE,WY
Yampa Valley Electric Association, Inc.	CO,WY
Yazoo Valley Electric Power Association	MS
York Electric Cooperative, Inc.	SC

Curtailment Service Providers

Comperio Energy LLC, d/b/a ClearChoice Energy	IL,PA
EnerNOC, Inc.	AL,AZ,CA,CO,CT,FL, GA,ID,KY,MA,ME, MS,NC,NH,NM,NY, RI,TN,TX,VA,VT,WA
Freedom Energy Logistics LLC	CT,MA,ME,NH,RI
Galt Power	PA
Hess Corporation	CT
Virtual Energy LLC	NC

Federal Utilities

Colorado River Indian Irrigation Project	AZ
Mission Valley Power	MT
Southwestern Power Administration	AR,MO,OK
Tennessee Valley Authority	AL,GA,KY,MS,NC,TN,VA
Western Area Power Administration	AZ,CA,CO,IA,KS,MN, MT,ND,NE,NJ

Investor Owned Utilities

AEP Texas Central Company	TX
AEP Texas North Company	TX
Ajo Improvement Company	AZ
Alabama Power Company	AL
Alcoa Power Generating, Inc.	IN
ALLETE Inc.	MN
Alpena Power Company	MI
Amana Society Service Co.	IA
Aniak Light & Power Co., Inc.	AK
Appalachian Power Company	VA,WV
Arizona Public Service Company	AZ
Atlantic City Electric Company	NJ
Avista Corporation, dba Avista Utilities	ID,WA
Baltimore Gas and Electric Company	MD
Bangor Hydro Electric Company	ME
Bear Valley Electric Service	CA
Black Diamond Power Company	WV
Black Hills Power, Inc.	MT,SD,WY
Black Hills/Colorado Electric Utility Co. LP	CO
Cap Rock Energy Corporation	TX
CenterPoint Energy Houston Electric, LLC	TX
Central Hudson Gas & Electric Corporation	NY
Central Illinois Light Co	IL
Central Illinois Pub Serv Co,	IL
Central Maine Power Company	ME
Central Vermont Public Service Corporation	VT
Cheyenne Light Fuel and Power	WY
Chitina Electric, Inc.	AK
Citizens Electric Co	PA
Cleco Power LLC	LA
Cleveland Electric Illuminating Co	OH
Columbus Southern Power Company	OH
Commonwealth Edison Company	IL
Competitive Energy Services, LLC	ME
Connecticut Light and Power Co	CT
Consolidated Edison Company of New York	NY
Consumers Energy Company	MI
Dahlberg Light and Power Company	WI
Delmarva Power & Light Company	DE,MD
Duke Energy Carolinas, LLC	NC,SC
Duke Energy Corporation	IN,KY,NC,OH,SC
Duke Energy Indiana Inc	IN
Duke Energy Kentucky, Inc.	KY
Duquesne Light Company	PA
El Paso Electric Company	NM,TX
Elk Power Company	WV
Empire Direct Electric Company	AR,KS,MO,OK
Entergy Arkansas, Inc.	AR
Entergy Gulf States Louisiana, LLC	LA
Entergy Louisiana, Inc.	LA
Entergy Mississippi, Inc.	MS
Entergy New Orleans, Inc.	LA
Entergy Texas, Inc.	TX
Farmington River Power Company	CT
Fitchburg Gas and Electric Light Company	MA
Florida Power & Light, Co.	FL
Florida Public Utilities	FL
Georgia Power	GA
Granite State Electric Company	NH
Green Mountain Power Corporation	VT
Gulf Power Company	FL
Gustavus Electric Company	AK

Investor Owned Utilities (Continued)

Hawaiian Electric	HI
Idaho Power Company	ID,OR
Illinois Power Co	IL
Indiana Michigan Power Company	IN,MI
Indiana-Kentucky Electric Corporation	IN
Indianapolis Power & Light Company	IN
Interstate Power and Light Company	IA,MN
Jersey Central Power & Light Co	NJ
Kansas City Power & Light Company	KS,MO
KCP&L Greater Missouri Operation Company	MO
Kentucky Power Company	KY
Kentucky Utilities	KY
Kingsport Power Company	TN
Louisville Gas & Electric Co	KY
Maine Public Service Company	ME
Massachusetts Electric Company	MA
Maui Electric Company, Ltd	HI
McGrath Light and Power	AK
Metropolitan Edison Co	PA
MidAmerican Energy Company	IA,IL,SD
Mississippi Power Company	MS
Monongahela Power Company d/b/a Allegheny Power	WV
Mt. Carmel Public Utility Co.	IL
Nantucket Electric Company	MA
Napakiak Ircinraq Power Company	AK
Nevada Power Company	NV
New York Electric & Gas Corporation	NY
Niagara Mohawk Power Corporation	NY
North Central Power Co., Inc.	WI
Northern Indiana Public Service Co.	IN
NorthWestern Energy	SD
Nstar Electric	MA
OGE Energy Corporation	AR,OK
Ohio Edison Co.	OH
Ohio Power Company	OH
Ohio Valley Electric Corporation	IN
Omya Inc.	VT
Oncor Electric Delivery Company LLC	TX
Otter Tail Power Co.	MN,ND,SD
Pacific Gas and Electric Company	CA
PacifiCorp	CA,ID,OR,UT,WA,WY
PECO Energy	PA
Pennsylvania Electric Co	PA
Pennsylvania Power Co	PA
Portland General Electric Company	OR
Potomac Edison Company d/b/a Allegheny Power	MD,VA,WV
Potomac Electric Power Company	DC,MD
PPL Electric Utilities	NY,PA
Progress Energy Carolinas	NC,SC
Progress Energy Florida	FL
Public Service Co of NH	NH
Public Service Company of New Mexico	NM
Public Service Company of Oklahoma	OK
Public Service Electric & Gas Company	NJ
Puget Sound Energy, Inc.	WA
Rochester Gas & Electric Corporation	NY
Safe Harbor Water Power Corporation	PA
San Diego Gas & Electric Company	CA
Sierra Pacific Power Company	NV
South Carolina Electric & Gas Company	SC
Southern California Edison	CA
Southern Indiana Gas & Electric Co.	IN
Southwestern Electric Power Company	AR,LA,TX
Superior Water Light and Power	WI
Tampa Electric Company	FL
Tanana Power Company	AK
The Dayton Power and Light Company	OH
The Detroit Edison Company	MI
The Morenci Water and Electric Company	AZ
The Narragansett Electric Company	RI
The Toledo Edison Co	OH
The United Illuminating Company	CT
Tucson Electric Power Co.	AZ
UGI Utilities, Inc	PA
Union Electric Company	MO
Union Power Company	WV
Unitil Energy Systems, Inc.	NH
Upper Peninsula Power Company	MI
Vermont Marble Power Division of Omya Inc.	VT
Virginia Electric and Power Company	NC,VA
West Penn Power Company d/b/a Allegheny Power	PA
Western Massachusetts Electric Co	MA
Wheeling Power Company	WV
Wisconsin Electric Power Company	MI,WI
Wisconsin Power and Light Company	WI
Wisconsin Public Service Corporation	MI,WI
Wisconsin River Power Company	WI
XCEL d/b/a Northern States Power Co – Minnesota	MN,ND,SD
XCEL d/b/a Northern States Power Co - Wisconsin	MI,WI
XCEL d/b/a Public Service Co of Colorado	CO
XCEL d/b/a Southwestern Public Service Co	NM,TX

Municipal Power Agencies

Indiana Municipal Power Agency	IN
Long Island Power Authority	NY
Massachusetts Municipal Wholesale Electric Company	MA
Minnesota Municipal Power Agency	MN
Municipal Electric Authority of Georgia	GA
Municipal Energy Agency of Mississippi	MS
New York Municipal Power Agency	NY
Northern Municipal Power Agency	MN
Oklahoma Municipal Power Authority	OK
Piedmont Municipal Power Agency	SC
Sacramento Municipal Utility District	CA
Southern Minnesota Municipal Power Agency	MN
Springville Light & Power	UT
Texas Municipal Power Agency	TX
Tuolumne Public Power Agency	CA
Utah Municipal Power Agency	UT
Walters Public Works Authority	OK

Washington City Power	UT
Wyoming Municipal Power Agency	WY

Municipally Owned Utilities

Adrian Public Utilities	MN
Aitkin Public Utilities	MN
Albany Water, Gas & Light Commission	GA
Albertville Municipal Utilities Board	AL
Algoma Utility Commission	WI
Alta Municipal Utilities	IA
Ames, City of	IA
Anita Municipal Utilities	IA
Arcadia Electric Utility	WI
Art Bahr	WI
Athens Utilities Board	TN
Atlantic Municipal Utilities	IA
Auburn Board of Public Works	NE
Austin Energy	TX
Austin Utilities	MN
Badger Power Marketing Authority of WI Inc	WI
Bainbridge Municipal Electric Utility	IN
Bamberg Board of Public Works	SC
Bancroft Municipal Utilities	IA
Baraga Electric Utility	MI
Bardwell City Utilities	KY
Barnesville Municipal Utility	MN
Barton Village, Inc.	VT
Bastrop Power & Light	TX
Bath Electric Gas & Water Systems	NY
Beaches Energy Services	FL
Beaver City Corporation	UT
Belmont Light & Water	WI
Benton County Electric System	TN
Benton Electric System	TN
Berlin Town of MD	MD
Biwabik Public Utilities	MN
Black River Falls Municipal Electric & Water	WI
Blooming Prairie Public Utility Commission	MN
Bluffton Utilities	IN
Board of Public Utilities, City of McPherson	KS
Board of Water, Electric & Communications	IA
Bolivar Energy Authority	TN
Borough of Butler	NJ
Borough of Ellwood City	PA
Borough of Goldsboro	PA
Borough of Hatfield	PA
Borough of Lavallette	NJ
Borough of Mont Alto	PA
Borough of New Wilmington	PA
Borough of Park Ridge	NJ
Borough of Royalton	PA
Borough of Smethport	PA
Borough of Wampum	PA
Borough of Watsontown	PA
Borough of Weatherly, PA	PA
Boscobel Municipal Utilities	WI
Bowling Green Municipal Utilities	KY
Brainerd Public Utilities	MN

Brigham City Corporation	UT
Brodhead Water & Light Commission	WI
Brooklyn Municipal Utilities	IA
Brownsville Public Utilities Board	TX
Brownsville Utility Department	TN
Bryan Texas Utilities	TX
Burlington Electric Department	VT
Cairo Public Utility Company	IL
Canton Municipal Utilities	MS
Carroll County Electric Department	TN
Carrollton Board of Public Works	MO
Carthage Water & Electric Plant	MO
Cascade Municipal Utilities	IA
Catawissa Borough	PA
Cedar Falls Utilities	IA
Cedarburg Light & Water Commission	WI
Centerville Municipal Power & Light	IN
Chickamauga Electric System	GA
Chicopee Municipal Lighting Plant	MA
City and Borough of Yakutat d/b/a Yakutat Power	AK
City of Abbeville	SC
City of Afton	IA
City of Albermarle	NC
City of Alcoa Electric Department	TN
City of Alexandria	LA
City of Alliance	NE
City Of Alma	KS
City of Alpha	MN
City of Altamont	IL
City of Anaheim	AK
City of Anoka	MN
City of Ansley	NE
City of Arapahoe	NE
City of Arma	KS
City of Attica	KS
City of Augusta	KS
City of Ava	MO
City of Azusa	CA
City of Bandon	OR
City of Bartow	FL
City of Baudette	MN
City of Bedford	VA
City of Belleville	KS
City of Beloit	KS
City of Benkelman	NE
City of Bentonville	AR
City of Berea Municipal Utilities	KY
City of Big Stone	SD
City of Blakely	GA
City of Blanding	UT
City of Bloomfield	IA
City of Blue Hill	NE
City of Boulder City	NV
City of Bountiful	UT
City of Bowie	TX
City of Brady	TX
City of Breda	IA

Municipally Owned Utilities (Continued)

City of Breese	IL
City of Bridgeport	NE
City of Bronson	KS
City of Brookings	SD
City of Brownton	MN
City of Brundidge	AL
City of Buffalo	MN
City of Buford	GA
City of Burke	SD
City of Burlington	CO
City of Burwell	NE
City of Bushnell	IL
City of Butler	MO
City of Cabool	MO
City of Cairo	GA
City of Caledonia	MN
City of Caliente	NV
City of Callender	IA
City of Camden	SC
City of Campbell	MO
City of Carlyle	IL
City of Carmi	IL
City of Cascade Locks	OR
City of Castroville	TX
City of Central City	NE
City of Centralia	MO
City of Chanute	KS
City of Charlevoix	MI
City of Chaska	MN
City of Chattahoochee	FL
City of Chetopa	KS
City of Chewelah	WA
City of Chignik	AK
City of Clewiston	FL
City of Clinton, Combined Utility System	SC
City of Clintonville	WI
City of Cody	WY
City of Coffeyville	KS
City of Colby	KS
City of Coleman	TX
City of Collins	MS
City of Collinsville	OK
City of Columbia	MO
City of Columbiana	OH
City of Columbus, Division of Power and Water	OH
City of Comanche	OK
City of Commerce	GA
City of Crystal Falls	MI
City of Cuero	TX
City of Curtis	NE
City of Cushing	OK
City of Cuyahoga Falls Electric Department	OH
City of Danville	IA
City of David City	NE
City of Delco	ID
City of Denton	TX
City of Deshler	NE
City of Detroit	MI
City of Doerun	GA
City of Dover	OH
City of Dover Public Utilities	DE
City of Drain	OR
City of Duncan	OK
City of Durant, Mississippi	MS
City of Dysart	IA
City of Edmond Electric	OK
City of El Dorado Springs	MO
City of Elba	AL
City of Elberton	GA
City of Eldorado	OK
City of Elk Point	SD
City of Ellaville	GA
City of Ellensburg	WA
City of Ellsworth	IA
City of Ely - Ely Utilities Commission	MN
City of Enterprise	UT
City of Escondido	CA
City of Estherville	IA
City of Eudora	KS
City of Evergreen	AL
City of Fairbury	NE
City of Faith	SD
City of Falls City	NE
City of Farmersville	TX
City of Farmington	MO
City of Fayette	MO
City of Fennimore	WI
City of Flatonia	TX
City of Flora	IL
City of Floresville Electric Light & Power System	TX
City of Fonda	IA
City of Forest Grove Light and Power	OR
City of Fort Collins	CO
City of Fort Meade	FL
City of Fosston	MN
City of Fountain	CO
City of Franklin	VA
City of Frederick	OK
City of Fulton	MO
City of Galion	OH
City of Gallatin	MO
City of Garden City	KS
City of Garland	TX
City of Gas City	IN
City of Gastonia	NC
City of Geneseo	IL
City of Giddings	TX
City of Gillette	WY
City of Girard	KS
City of Glasco	KS
City of Glendale	CA
City of Goldthwaite	TX
City of Gothenburg	NE
City of Granbury	TX

Municipally Owned Utilities (Continued)

City of Grand Island	NE
City of Grand Junction	IA
City of Granite	OK
City of Green Cove Springs Electric Utility	FL
City Of Greenfield	IN
City of Gridley	CA
City of Groton	SD
City of Groton Dept of Utilities	CT
City of Guttenberg	IA
City of Hall City	KS
City of Hamilton	OH
City of Hannibal	MO
City of Hart	MI
City of Haven	KS
City of Hebron	NE
City of Helper	UT
City of Hempstead	TX
City of Hermann	MO
City of Hickman	NE
City of High Point	NC
City of Highland	IL
City of Hill City	KS
City of Hillsboro	ND
City of Holyrood	KS
City of Homestead	FL
City of Hominy	OK
City of Hope	ND
City of Howard	SD
City of Hubbard Light Dept.	OH
City of Hudson	OH
City of Hugoton	KS
City of Hunnewell	MO
City of Independence	MO
City Of Iola	KS
City of Isabel	KS
City of Jackson	GA
City of Janesville	MN
City of Jasper	IN
City of Jonesville	LA
City of Kasson	MN
City of Kennett	MO
City of Kings Mountain	NC
City of Kosciusko	MS
City of La Plata	MO
City of Lafayette	GA
City of LaGrange, Georgia	GA
City of LaHarpe	KS
City of Lake City Electric Utility	MN
City of Lake View	IA
City of Lake Worth Utilities	FL
City of Lakefield	MN
City of Lakeland, Lakeland Electric	FL
City of Lakin	KS
City of Lakota	ND
City of Lamar Utilities Board	CO
City of Larchwood	IA
City of Larned	KS
City of Las Animas Municipal Light and Power	CO
City of Laurens	IA
City of Laurinburg	NC
City of Lawrenceville	GA
City of Lebanon	OH
City of Lebanon Utilities	IN
City of Leesburg	FL
City of Lehigh	IA
City of Lewes Board of Public Works	DE
City of Liberal	MO
City of Liberty	TX
City of Lincoln Center	KS
City of Lincoln Electric System	NE
City of Linton	IN
City of Livingston	TX
City of Lockhart	TX
City of Lockwood	MO
City of Lodi	CA
City of Lucas	KS
City of Lumberton	NC
City of Luverne	MN
City of Mabel	MN
City of Maddock	ND
City of Mangum	OK
City of Mansfield	MO
City of Marceline	MO
City of Marshall	IL
City of Marshfield	WI
City of Maryville Electric Department	TN
City of McLaughlin	SD
City of McLeansboro	IL
City of Medford	WI
City of Memphis	MO
City of Mesa	AZ
City of Metropolis	IL
City of Minden	LA
City of Mitchell	NE
City of Monroe	GA
City of Monroe City	MO
City of Monroe, NC	NC
City of Monticello	GA
City of Moore Haven	FL
City of Moran	KS
City of Morrill	KS
City of Mount Dora	FL
City of Mount Vernon	MO
City of Mountain Iron	MN
City of Mountain Lake	MN
City of Mountain View	MO
City of Murray	UT
City of Naperville	IL
City of Neligh	NE
City of Neodesha	KS
City of New Lisbon	WI
City of New Martinsville	WV
City of Newberry	FL
City of Newburg	MO

Municipally Owned Utilities (Continued)

City of Newton	IL
City of Newton Falls	OH
City of Niles Light Dept.	OH
City of Nixa Utilities	MO
City of North Little Rock-Electric Department	AR
City of Northwood Utilities	ND
City of Norton	KS
City of Norway Dept. of Power & Light	MI
City of Odessa	MO
City of Onida	SD
City of Orangeburg Dept. of Public Utilities	SC
City of Ord	NE
City of Orient	IA
City of Osawatomie	KS
City of Osborne	KS
City of Osceola	MO
City of Oxford	KS
City of Painesville Municipal Electric Plant	OH
City of Palo Alto Utilities	CA
City of Perry	MO
City of Peru	IL
City of Petoskey	MI
City of Pierz	MN
City of Plankinton	SD
City of Plummer	ID
City of Poplar Bluff	MO
City of Port Angeles	WA
City of Powell	WY
City of Prescott	AR
City of Providence	KY
City of Purcell	OK
City of Radford	VA
City of Rancho Cucamonga	CA
City of Randall	MN
City of Rayne	LA
City of Redding Electric Utility	CA
City of Richland	MO
City of Richland Energy Services	WA
City of Robertsdale	AL
City of Rock Falls	IL
City of Rock Hill	SC
City of Roodhouse	IL
City of Roseau	MN
City of Roseville	CA
City of Round Lake	MN
City of Rupert	ID
City of Ruston	LA
City of Saint Peter	MN
City of Salamanca Board of Public Utilities	NY
City of Salem	VA
City of Sanborn	IA
City of Schulenburg	TX
City of Scottsburg Municipal Electric Utility	IN
City of Scranton	KS
City of Scribner	NE
City of Seaford	DE
City of Seattle Light Department	WA
City of Seguin	TX
City of Seneca	SC
City of Sergeant Bluff	IA
City of Seward	NE
City of Sheboygan Falls	WI
City of Shelbina	MO
City of Shiner	TX
City of Shullsburg	WI
City of Sikeston Board of Municipal Utilities	MO
City of Sioux Center	IA
City of Smithville	TX
City of Southport	NC
City of Spring Grove	MN
City of Springfield	IL
City of St Marys	KS
City of St. Clairsville	OH
City of St. Francis	KS
City of St. George	UT
City of St. James	MN
City of St. John	KS
City of Stanhope	IA
City of State Center	IA
City of Steelville	MO
City of Stephen	MN
City of Stephenson	MI
City of Stilwell	OK
City of Stockton	KS
City of Stratford	IA
City of Strawberry Point	IA
City of Sullivan	MO
City of Sylvester	GA
City of Tallahassee	FL
City of Thayer	MO
City of Thomasville	GA
City of Traer	IA
City of Troy	AL
City of Udall	KS
City of Unalaska	AK
City of Union	SC
City of Valley City	ND
City of Vandalia	MO
City of Vermillion	SD
City of Wadena Electric & Water	MN
City of Wadsworth	OH
City Of Wakefield	MI
City of Warroad	MN
City of Washington	NC
City of Waterloo	IL
City of Watertown	NY
City of Watonga	OK
City of Waynesville	MO
City of Waynoka	OK
City of Weimar	TX
City of Weiser	ID
City of West Liberty	IA
City of Westerville	OH
City of Westfield	MA

Municipally Owned Utilities (Continued)

City of White Mountain Utilities	AK
City of Whitesboro	TX
CIty of Willow Springs	MO
City of Windom	MN
City of Winfield	KS
City of Winnfield	LA
City of Wray	CO
City of Yoakum	TX
City Utilities of Springfield	MO
City Water & Light Plant of the City of Jonesboro	AR
Clarksville Light & Water Co.	AR
Columbia Power & Water Systems	TN
Columbus Water & Light Dept.	WI
Concord Municipal Utility	MA
Conway Corporation	AR
Corbin City Utilities Commission	KY
Corwith Municipal Utilities	IA
Cozad Board of Public Works	NE
Crawfordsville Electric Light & Power	IN
Cuba City Electric & Water Utility	WI
Cumberland, City of	WI
Decatur Utilities	AL
Delano Municipal Utilities	MN
Delta Municipal Light and Power	CO
Denison Municipal Utilities	IA
Dickson Electric Department	TN
Dublin Municipal Electric	IN
Duncannon Borough	PA
Dyersburg Electric System	TN
Eagle River Light & Water Commission	WI
Easley Combined Utility System	SC
East Grand Forks Water and Light	MN
Easton Utilities Commission	MD
Electric and Water Plant Board of the City of Frankfort	KY
Elk River Municipal Utilities - City of Elk River	MN
Erwin Utilities	TN
Eugene Water & Electric Board	OR
Evansville Water & Light	WI
Fairburn Utilities	GA
Fillmore City Corporation	UT
Fitzgerald Wtr Lgt & Bond Comm	GA
Florence Utility Commission	WI
Forest City Municipal Utilities	IA
Fort Payne Improvement Authority	AL
Fort Pierce Utilities Authority	FL
Franklin Electric Plant Board	KY
Gaffney Board of Public Works	SC
Gainesville Regional Utilities	FL
Gallatin Department of Electricity	TN
Garnett Municipal Electric	KS
Geary Utilities Authority	OK
Glasgow Electric Plant Board	KY
Glencoe Light and Power Commission	MN
Glenwood Springs City of	CO
Grafton Electric	IA
Grand Haven Board of Light and Power	MI
Grand Marais Public Utilities	MN
Grand Rapids Public Utilities Commission	MN
Greeneville Light & Power System	AL
Greenfield Municipal Utilities	IA
Greenwood Utilities Commission	MS
Groton Electric Light	MA
Guam Power Authority	GU
Guntersville Electric Board	AL
Harriman Utility Board	TN
Harrisonburg Electric Commission	VA
Hartford Utilities	WI
Hartley Municipal Utilities	IA
Hartselle Utilities	AL
Hastings City of	NE
Hawarden Municipal Utilities	IA
Heber Light and Power	UT
Henderson City Utility Commission	KY
Hermiston Energy Services	OR
Hillsdale Board of Public Utilities	MI
Holland Board of Public Works	MI
Holy Springs Utility Department	MS
Hooversville Boro Elec Lgt Co.	PA
Hope Water and Light Commission	AR
Hopkinsville Electric System	KY
Hudson Municipal Electric Utility	IA
Humboldt Utilities	TN
Huntsville Utilities	AL
Hurricane City Power	UT
Hustisford Utilities	WI
Hyrum City Corp.	UT
Independence Light & Power	IA
Indianola Municipal Utilities	IA
Ipnatchiaq Electric Company	AK
Jackson Energy Authority	TN
Jamestown Board of Public Utilities	NY
JEA	FL
Jefferson Water & Light Dept.	WI
Jewett City Dept. of Public Utilities	CT
Juneau Utility Commission	WI
Kansas City Board of Public Utilities	KS
Kaukauna Utilities	WI
Kaysville City Corporation	UT
Kenyon Municipal Utilities	MN
Kerrville Public Utility Board	TX
Ketchikan Public Utilities	AK
Kimballton Municipal Utilities	IA
Kingman City of	KS
Kissimmee Utility Authority	FL
Knoxville Utilities Board	TN
La Farge Municipal Electric Utility	WI
La Junta Municipal Utilities	CO
Lafayette Utilities System	LA
Lafollette Utilities Board	TN
Lake Mills Light & Water Dept.	WI
Lake Mills Municipal Utilities	IA
Lake Placid Village, Inc.	NY
Lampasas City of	TX

Municipally Owned Utilities (Continued)

L'anse Electric Utility	MI
Laurens Commission of Public Works	SC
Lawrenceburg Municipal Utility	IN
Lexington Electric System	TN
Litchfield Public Utilities	MN
Littleton Water and Light Department	NH
Lodi Municipal Light & Water Utility	WI
Lodi Village of	OH
Logan City Light and Power	UT
Logansport Municipal Utilities	IN
Longmont Power & Communications	CO
Los Angeles Department of Water and Power	CA
Lowell Light and Power	MI
Lubbock Power & Light	TX
Madelia Municipal Light & Power	MN
Madison Electric	ME
Manilla Municipal Utilities	IA
Manti City	UT
Maquoketa Municipal Electric Utility	IA
Marquette Board of Light and Power	MI
Marshall Municipal Utilities	MO
McMinnville Electric System	TN
Melrose Public Utilities	MN
Memphis Light, Gas & Water Division	TN
Menasha Electric & Water Utilities	WI
Milton-Freewater City Light & Power	OR
Moorhead Public Service	MN
Morgan City Corporation	UT
Morristown Utilities Commission	TN
Mount Horeb Electric Utility	WI
Mount Pleasant Municipal Utilities	IA
Mt. Pleasant City TN	TN
Navajo Tribal Utility Authority	AZ,NM
Nebraska City Utilities	NE
Negaunee Electric Department	MI
New Castle Municipal Services Commission	DE
New Glarus Light & Water Works	WI
New Hampton Municipal Light Plant	IA
New Hampton Village Precinct	NH
New Holstein Public Utility	WI
New London Electric & Water Utility	WI
New Richmond Municipal Electric Utility	WI
Newbern Electric Water & Gas	TN
Newkirk Municipal Authority	OK
Newport Utilities Board	TN
North Branch Water & Light Comm.	MN
Norwalk Third Taxing District	CT
Ocala Utility Services	FL
Oconomowoc Utilities	WI
Oconto Falls Water & Light Commission	WI
Orlando Utilities Commission	FL
Orrville Utilities	OH
Osage Municipal Utilities	IA
Ottawa, City of	KS
Owatonna Public Utilities	MN
Owensboro Municipal Utilities	KY
Page Electric Utility	AZ
Paragonah Town	UT
Paragould Light Water and Cable	AR
Paris Board of Public Utilities	TN
Pasadena Water & Power	CA
Pascoag Utility District	RI
Payson City	UT
Pella City of	IA
Peru Utilities	IN
PES Energize - Pulaski Electric System	TN
Philadelphia Utilities	MS
Pierre Municipal Utilities	SD
Piggott Light and Water	AR
Plattsburgh Municipal Lighting Department	NY
Plymouth Utilities	WI
Ponca City Utility Authority	OK
Prairie du Sac Municipal Electric & Water	WI
Precinct of Woodsville	NH
Price Municipal Corporation	UT
Princeton Municipal Light Department	MA
Princeton Public Utilities	MN
Proctor Public Utilities Commission	MN
Provo City Corp	UT
Public Service Commission of Yazoo City	MS
Public Works Commission of the City of Fayetteville	NC
Reedsburg Utility Commission	WI
Reedy Creek Improvement Disrtrict	FL
Rensselaer Municipal Electric Utility	IN
Reynolds, Village of	NE
Rice Lake Utilities	WI
Richland Center Electric Utility	WI
Richmond Power and Light	IN
Ripley Power and Light	TN
River Falls Municipal Utility	WI
Riverside Public Utilities	CA
Rochelle Municipal Utilities	IL
Rochester Public Utilities	MN
Rock Port Municipal Utilities	MO
Rock Rapids Municipal Utility	IA
Rockford Municipal Light Plan	IA
Russellville Electric Board	AL
Russellville Electric Plant Board	KY
Santa Clara City	UT
Sebewaing Light & Water	MI
Sevier County Electric System	TN
Shakopee Public Utilities Commission	MN
Shawano Municipal Utilities	WI
Sheffield Utilities	AL
Shelbyville Power System	TN
Silicon Valley Power	CA
Sioux Falls Municipal Light & Power	SD
Sitka City & Borough of	AK
Sleepy Eye Public Utilities	MN
Slinger Utilities	WI
Smithville Electric System	TN
South Norwalk Electric and Water	CT
South Vienna Corporation	OH

Municipally Owned Utilities (Continued)

Spencer Municipal Utilities	IA
Spooner, City of	WI
Spring City Corp	UT
Spring Valley Public Utilities	MN
Springfield Public Utilities	MN
Story City Municipal Electric Utility	IA
Stoughton Electric Utility	WI
Straughn Municipal Electric	IN
Sturgeon Bay Utilities	WI
Sun Prairie Water & Light Commission	WI
Superior Utilities, City of Superior Nebraska	NE
Tacoma Public Utilities	WA
Tatitlek Electric Utility	AK
Tell City Electric Department	IN
Tenakee Springs Electric Utility	AK
Terrebonne Parish Consolidated Government	LA
The City of Holyoke Gas and Electric Department	MA
The City of Plainview	NE
The Hagerstown Light Department	MD
Thurmont Municipal Light Company	MD
Tillamook People's Utility District	OR
Tipton Municipal Electric Utility	IN
Tipton Municipal Utilities	IA
Town of Argos	IN
Town of Avilla	IN
Town of Ayden	NC
Town of Black Creek	NC
Town of Bostic	NC
Town of Braintree Electric Light Department	MA
Town of Brooklyn	IN
Town of Brookston	IN
Town of Center - Municipal Light & Power	CO
Town of Clayton	NC
Town of Coatesville	IN
Town of Culpeper	VA
Town of Dallas	NC
Town of Deaver	WY
Town of Edenton	NC
Town of Forest City	NC
Town of Frederick	CO
Town of Fredonia	AZ
Town of Front Royal	VA
Town of Granite Falls	NC
Town of Guernsey	WY
Town of Gueydan	LA
Town of Hagerstown	IN
Town of Haxtun	CO
Town of Highlands	NC
Town of Holden	UT
Town of Hookerton	NC
Town of Julesburg	CO
Town of Knightstown	IN
Town of Ladoga	IN
Town of Landis	NC
Town of Laverne	OK
Town of Lucama	NC
Town of Lyons	CO
Town of Manitou	OK
Town of Massena	NY
Town of Merrimac Municipal Light Department	MA
Town of Middletown	DE
Town of Montezuma	IN
Town Of Oak City	UT
Town of Pine Bluffs	WY
Town of Pittsboro	IN
Town of Prosperity	SC
Town of Red Springs	NC
Town of Robersonville	NC
Town of Ruston	WA
Town of Ryan	OK
Town of Sharpsburg	NC
Town of South Hadley	MA
Town of South Whitley	IN
Town of Spiceland	IN
Town of Steilacoom	WA
Town of Stowe Electric Department	VT
Town of Wallingford, Department of Public Utilities	CT
Town of Williamsport	MA
Town of Winamac	IN
Trempealeau Municipal Electric Utility	WI
Trenton Municipal Utilities	MO
Tullahoma Board of Public Utilities	TN
Two Rivers Water & Light Utility	WI
Utilities Commission, City of New Smyrna Beach	FL
Van Buren Light & Power District	ME
Village of Akron	NY
Village of Albany	IL
Village of Angelica	NY
Village of Arcade	NY
Village of Bergen	NY
Village of Black Earth	WI
Village of Brocton	NY
Village of Callaway	NE
Village of Carey Electric	OH
Village of Cashton	WI
Village of Castile	NY
Village of Clinton	MI
Village of Daggett	MI
Village of Davenport	NE
Village of Decatur	NE
Village of Deshler	OH
Village of Endicott	NE
Village of Endicott Municipal Light	NY
Village of Fairport	NY
Village of Frankfort	NY
Village of Freeport	NY
Village of Genoa	OH
Village of Glouster	OH
Village of Grafton	OH
Village of Greene	NY
Village of Greenport	NY
Village of Hamilton	NY
Village of Hampton	NE

Municipally Owned Utilities (Continued)

Village of Holbrook	NE
Village of Hyde Park, Inc.	VT
Village of Jackson Center	OH
Village of Ladd	IL
Village of Little Valley	NY
Village of Lucas	OH
Village of Lydonville Electric Department	VT
Village of Marshallville	OH
Village of Mayville	NY
Village of Mendon	OH
Village of Merrillan	WI
Village of Minster	OH
Village of Northfield Electric Department	VT
Village of Orleans Electric Dept. Inc.	VT
Village of Oxford	NE
Village of Paw Paw	MI
Village of Pemberville	OH
Village of Philadelphia	NY
Village of Prague	NE
Village of Richmondville	NY
Village of Riverton	IL
Village of Rockville Centre	NY
Village of Sherburne	NY
Village of Shickley	NE
Village of Shiloh	OH
Village of Silver Springs Municipal Electric	NY
Village of Solvay	NY
Village of Spalding	NE
Village of Stratford	WI
Village of Stratton	NC
Village of Talmage	NE
Village of Trenton	NE
Village of Versailles	OH
Village of Waynesfield	OH
Village of Westfield	NY
Village of Wharton	OH
Village of Winnetka, Water & Electric Department	IL
Village of Woodsfield	OH
Vinton Municipal Electric Utility	IA
Wadsworth Electric and Communications	OH
Wagoner Public Works Authority	OK
Waterloo Water & Light Commission	WI
Waunakee Water & Light Commission	WI
Waupun Public Utilities	WI
Weakley County Municipal Electric System	TN
Wellesley Municipal Light Plant	MA
Westbrook Public Utilities	MN
Westby Municipal Electric Utility	WI
Whitehall Municipal Electric Utility	WI
Willmar Municipal Utilities	MN
Wilton Municipal Light and Power	IA
Wonewoc Electric & Water Department	WI

Political Subdivisions

Alamo Power District #3	NV
Alaska Energy Authority	AK
Brazos River Authority	TX
Butler Public Power District	NE
Canby Utility Board	OR
Central Lincoln People's Utility District	OR
Columbia River Peoples Utility District	OR
Crisp County Power Commission	GA
Cuming County Public Power District	NE
Electrical Dist No3 Pinal Cnty	AZ
Electrical District # 2	AZ
Electrical District No. 4, Pinal County, Arizona	AZ
Electrical District No. 5, Pinal County, Arizona	AZ
Elkhorn Rural Public Power District	NE
Emerald People's Utility District	OR
Energy Northwest	WA
Guadalupe-Blanco River Authority	TX
Imperial Irrigation District	CA
Kennebunk Light & Power District	ME
Kings River Conservation District	CA
Klickitat County Public Utility District No. 1	WA
Lincoln County Power District No. 1	NV
Loup River Public Power District	NE
Loup Valleys Rural Public Power District	NE
McCook Public Power District	NE
Midvale Irrigation District	WY
Mohegan Tribal Utility Authority	CT
Municipal Energy Agency of Nebraska	NE
North Central Public Power District	NE
Northern Wasco Co PUD	OR
Northwest Rural Public Power District	NE
Omaha Public Power District	NE
Perennial Public Power District	NE
Placer County Water Agency	CA
Platte River Power Authority	CO
Polk County Rural Public Power District	NE
Public Utility District No. 1 of Benton County	WA
Public Utility District No. 1 of Douglas County	WA
Public Utility District No. 1 of Grays Harbor County	WA
Public Utility District No. 1 of Pend Oreille County	WA
Public Utility District No. 1 of Wahkiakum County	WA
PUD #1 of Ferry County	WA
PUD No 3 of Mason County	WA
PUD No. 1 of Cowlitz County	WA
PUD No. 1 of Whatcom County	WA
Roosevelt Public Power District	NE
Salt River Project (SRP)	AZ
Seward County Public Power District	NE
Snohomish County Public Utility District #1	WA
South Feather Water and Power Agency	CA
Southern Public Power District	NE
Southwest Public Power District	NE
Strawberry Electric Service District	UT
Texas General Land Office	TX
Tohono O'odham Utility Authority	AZ
Tonopah Irrigation District	AZ
Turlock Irrigation District	CA

Political Subdivisions (Continued)

Twin Valleys Public Power District	NE
Utah Associated Municipal Power Systems	ID,NV,UT
Vera Water and Power	WA
WPPI Energy	WI

Retail Power Marketers

3 Phases Renewables LLS	CA
Agway Energy Services, LLC	NY
Central Electric Inc.	AK
Chain Lakes Power, LP., dba Simple Power, L.P	TX
Champion Energy Services, LLC	IL,PA,TX
Columbia Utilities Power, LLC	NY
Commerce Energy, Inc.	CA
CPL Retail Energy, LP	TX
Direct Energy Business, LLC (fka Strategic Energy, LLC)	CA,CT,IL,MA,MD,NJ, NY,OH,PA,TX
Direct Energy Services, LLC	CT
Direct Energy, LP	TX
Dominion Retail, Inc.	CT,MA,MD,ME,NY,OH,PA
Dow Hydrocarbons and Resources, LLC	TX
dPi Energy L.L.C	TX
Empire Natural Gas Corporation	NY
Energetix, Inc.	NY
Energy Cooperartive of New York	NY
Energy West Resources, Inc.	MT
Entergy Solutions LLC	MA,NY
Fulcrum Retail Energy LLC d/b/a Amigo Energy	TX
Integrys Energy Services of New York, Inc.	NY
Integrys Energy Services, Inc.	CT,DC,DE,IL,MA,MD, ME,MI,NH,NJ,NY,OH,PA,RI
Jack Rich, Inc. d/b/a Anthracite Power & Light	PA
Just Energy Texas	TX
KeySpan Energy Services Inc	NY
MC-Squared Energy Services, llc	IL
New York Industrial Energy Buyers, LLC	NY
NYSEG Solutions, Inc.	NY
Penstar Power, LLC	TX
Peoples Energy Services, Corp	IL
Shell Energy North America, LP	CA,NV,TX,WA
Suez Energy Resources North America	CT,DC,DE,IL,MA, MD, ME,NJ,NY,PA,TX
Tara Energy, LLC	TX
Texas Retail Energy, LLC	TX
TriEagle Energy, LLC	TX
TXU Energy Retail Company LLC	TX
U.S. Energy Partners LLC	NY
UGI Energy Services, Inc	PA
Wolverine Power Marketing Cooperative, Inc.	MI
WTU Retail Energy, LP	TX

RTO/ISOs

California Independent System Operator	CA
Electric Reliability Council of Texas Inc.	TX
ISO New England	MA
Midwest ISO	IN
New York Independent System Operator	NY
PJM Interconnection, LLC	PA
Southwest Power Pool, Inc	AR

State Utilities

Ak-Chin Energy Services	AZ
Arizona Power Authority	AZ
California Department of Water Resources	CA
Colorado River Commission of Nevada	NV
Custer Public Power District	NE
Dept of Water Resources/CA Energy Resources Sched.	CA
Grand River Dam Authority	OK
Nebraska Public Power District	NE,SD
New River Light and Power Company	NC
New York Power Authority	NY
Northeast Nebraska Public Power District	NE
Overton Power District No. 5	NV
PUD No 1 of Clark County	WA
South Carolina Public Service Authority	SC
South Central Public Power District	NE
Virginia Polytechnic Institute - Electric Service	VA
Wheat Belt Public Power District	NE

Transmission

Big Rivers Electric Corporation	KY
City of Peterson	MN
City of Whalan	MN
ITC Midwest	IA,IL,MN,MO
ITC Transmission	MI
Michigan Electric Transmission Company	MI
NW Electric Power Coop., Inc.	MO
Swans Island Electric Co-op Inc.	ME

Wholesale Power Marketers

BP Energy Company	TX
Cargill Power Markets LLC	MN
Conectiv Energy Supply, Inc.	DE
Dynegy Power Marketing Inc.	TX
Mirant Energy Trading, LLC	CA,MA,MD,NY,VA
MKEC	KS
PPL EnergyPlus LLC	PA
Select Energy, Inc.	CT
Sempra Generation	CA
Sunflower Electric Power Corp	KS
Tenaska Power Services, Co.	DE,TX
Toledo Bend Project Joint Operation	LA,TX

APPENDIX F: DEMAND RESPONSE PROGRAMS AND SERVICES AT RESPONDING ENTITIES

Appendix F lists entities that responded to the 2010 FERC Survey and indicated that they offer one or more demand response programs, organized by demand response program type.

Critical Peak Pricing

Adams Electric Cooperative, Inc.
Alabama Power Company
Brown County Rural Electrical Assn.
C & L Electric Cooperative Corporation
City of Gastonia
Clay Electric Cooperative, Inc.
Connecticut Light and Power Co
Crisp County Power Commission
El Paso Electric Company
Green Mountain Power Corporation
Guadalupe Valley Electric Cooperative, Inc.
Gulf Power Company
Gunnison County Electric Association, Inc.
Holy Cross Energy
Idaho Power Company
Jackson Electric Membership Corporation
Kentucky Utilities
Midwest Electric Inc
Pacific Gas and Electric Company
Richmond Power and Light
Rural Electric Cooperative,Inc.
Salt River Project (SRP)
San Patricio Electric Cooperative, Inc.
Santee Electric Cooperative Inc.
Sawnee Electric Membership Corporation
Southern California Edison
Tampa Electric Company
Town of Edenton
Wisconsin Public Service Corporation

Critical Peak Pricing with Load Control

Alabama Power Company
Blue Ridge Electric Membership Corporation
Bluestem Electric Cooperative Inc.
Brown County Rural Electrical Assn.
Cass County Electric Cooperative
Choptank Electric Cooperative, Inc.
City of Fort Collins
City of Hickman
City of High Point
City of Washington
Edgecombe-Martin County Electric Membership Corp.
EnergyUnited Electric Membership Corporation
Farmers Electric Cooperative, Inc.
Jackson Electric Cooperative, Inc
Midwest Electric Inc
New Castle Municipal Services Commission
New York Power Authority
Otter Tail Power Co.
Red River Valley Cooperative Power Association
Rutherford Electric Membership Corporation
Sangre De Cristo Electric Association, Inc
Tri-County Rural Electric Cooperative, Inc.
United Power, Inc

Demand Bidding & Buy-Back

Denton County Electric Cooperative, Inc.
Duke Energy Corporation
Idaho Cnty L&P Coop Assn, Inc.
Pacific Gas and Electric Company
Potomac Edison Company d/b/a Allegheny Power
Southern California Edison
Wheatland Electric Cooperative, Inc.
Wisconsin Public Service Corporation

Direct Load Control

A & N Electric Cooperative
Adams Electric Cooperative
Adams Electric Cooperative, Inc.
Adams-Columbia Electric Cooperative
Agralite Electric Cooperative
Alabama Power Company
Alcoa Power Generating, Inc.
Ames, City of
Arrowhead Electric Cooperative, Inc.
Ashley-Chicot Electric Cooperative, Incorporated
Atlantic City Electric Company
Austin Energy
Austin Utilities
Avista Corporation, dba Avista Utilities
Baltimore Gas and Electric Company
BARC Electric Cooperative
Barnesville Municipal Utility
Beaver City Corporation
Bedford Rural Electric Cooperative, Inc.
Blue Ridge Electric Membership Corporation
Bluestem Electric Cooperative Inc.
Boone Electric Cooperative
Brown County Rural Electrical Assn.
Brunswick Electric Membership Corporation
Buckeye Power, Inc.
Burlington Electric Department
Butler Public Power District
C & L Electric Cooperative Corporation
Capital Electric Cooperative, Inc.
Carroll Electric Cooperative Corporation
Cass County Electric Cooperative
Central Alabama Electric Cooperative

Direct Load Control (continued)

Central Electric Cooperative
Central Electric Cooperative, Inc.
Central Florida Electric Cooperative, Inc.
Central Georgia Electric Membership Corp
Central Illinois Pub Serv Co,
Central Vermont Public Service Corporation
Choptank Electric Cooperative, Inc.
City of Alliance
City of Big Stone
City of Breda
City of Columbia
City of Fort Collins
City of Gothenburg
City of Groton
City of Kasson
City of Northwood Utilities
City of Rock Hill
City of Roseville
City of Saint Peter
City of Sioux Center
City of Southport
City of St. James
City of Valley City
City of Vermillion
City of Wadena Electric & Water
City of Washington
Clay County Electric Cooperative Corporation
Clay-Union Electric Corporation
Clearwater-Polk Electric Cooperative, Inc.
Cleveland Electric Illuminating Co
Codington-Clark Electric Cooperative, Inc
Commonwealth Edison Company
Community Electric Cooperative
Connexus Energy
Consolidated Edison Company of New York
Cooperative Light and Power Association
Corn Belt Energy Corporation
Coweta-Fayette EMC
CPL Retail Energy, LP
Craighead Electric Cooperative Corporation
Crawfordsville Electric Light & Power
Crow Wing Cooperative Power & Light Company
Cuivre River Electric Cooperative, Inc
Custer Public Power District
Dairyland Power Cooperative
Dakota Electric Association
Delaware Electric Cooperative, Inc.
Delmarva Power & Light Company
Denison Municipal Utilities
Direct Energy, LP
Douglas Electric Cooperative, Inc
Duke Energy Corporation
Dunn County Electric Cooperative
Duquesne Light Company
Duquesne Light Company
East Grand Forks Water and Light
East River Electric Power Cooperative, Inc.
Elk River Municipal Utilities - City of Elk River
EnergyUnited Electric Membership Corporation
Entergy Arkansas, Inc.
Entergy Louisiana, Inc.
Excelsior Electric Membership Corporation (EMC)
Farmers Electric Cooperative Corporation
Farmers Rural Electric Cooperative Corporation
Federated Rural Electric Association
FEM Electric Association, Inc
First Electric Cooperative Corporation
Flint Electric Membership Corporation
Flint Hills Rural ECA, Inc
Florida Power & Light, Co.
Fulton County Rural Electric Membership Corporation
Grand Marais Public Utilities
Grand Rapids Public Utilities Commission
Grundy Electric Cooperative, Inc.
Guernsey-Muskingum Electric Cooperative, Inc.
Hawaiian Electric
Haywood Electric Membership Corporation
H-D Electric Cooperative, Inc
Henry County Rural Electric Membership Corporation
High Plains Power Inc.
Highline Electric Association
Horry Electric Cooperative, Inc.
Idaho Power Company
Illinois Rural Electric Cooperative
Indiana Michigan Power Company
Indianapolis Power & Light Company
Inter-county Energy Cooperative Cooperation
Interstate Power and Light Company
Itasca-Mantrap Cooperative Electrical Association
Jackson Electric Cooperative
Jackson Electric Membership Corporation
Jersey Central Power & Light Co
Kandiyohi Power Cooperative
Kansas City Power & Light Company
Kay Electric Cooperative
KCP&L Greater Missouri Operation Company
Kentucky Utilities
Kingsbury Electric Cooperative, Inc.
Lake Region Electric Cooperative
Lamb County Electric Cooperative
Lee County Electric Cooperative, Incorporated
Lighthouse Electric Cooperative, Inc.
Long Island Power Authority
Loup Valleys Rural Public Power District
Lyon Rural Electric Cooperative
Lyon-Lincoln Electric Cooperative, Inc.
Marshall Municipal Utilities
McLean Electric Cooperative, INC
McLeod Cooperative Power Association
Mecklenburg Electric Cooperative
Meeker Cooperative Light & Power Association
Menard Electric Cooperative
MidAmerican Energy Company
Midwest Electric Inc
Midwest Energy Cooperative
Midwest ISO
Mid-Yellowstone Electric Cooperative, Inc.
Mille Lacs Energy Cooperative
Milton-Freewater City Light & Power
Minnesota Valley Electric Cooperative
Minnkota Power Cooperative, Inc.
Mississippi County Electric Cooperative , Inc.
Moorhead Public Service

Direct Load Control (continued)

Mountain View Electric Association, Inc.
Municipal Commission of Boonville
NC Electric Membership Corp
Nevada Power Company
New Hampshire Electric Cooperative, Inc
New York Electric & Gas Corporation
Niobrara Electric Association
Nishnabotina Valley Rural Electric Cooperative
Nobles Cooperative Electric
North Arkansas Electric Cooperative, Incorporated
North Central Mo. Electric Coop
Northeastern REMC
Northern Neck Electric Cooperative
Northern Virginia Electric Cooperative
Northwest Rural Public Power District
Northwestern Rural Electric Coop Association, Inc.
Oahe Electric Coop Inc.
OGE Energy Corporation
Ohio Edison Co.
Osage Municipal Utilities
Osceola Electric Cooperative, Inc.
Otsego Electric Cooperative, Inc.
Otter Tail Power Co.
Pacific Gas and Electric Company
PacifiCorp
Panhandle Rural Electric Membership Association
Pee Dee Electric Membership Corp.
Pennsylvania Electric Co
Perennial Public Power District
Piedmont Electric Membership Corporation
Platte-Clay Electric Cooperative, Inc.
Polk County Rural Public Power District
Potomac Electric Power Company
Prince George Electric Cooperative
Progress Energy Carolinas
Progress Energy Florida
Public Service Company of New Mexico
Public Service Electric & Gas Company
Puget Sound Energy, Inc.
Randolph Electric Membership Corporation
Rappahannock Electric Cooperative
REA Energy Cooperative, Inc.
Red River Valley Cooperative Power Association
Renville-Sibley Cooperative Power Association
Rice Lake Utilities
Richmond Power and Light
Rochester Public Utilities
Rolling Hills Electric Cooperative, Inc.
Roughrider Electric Cooperative, Inc.
Rutherford Electric Membership Corporation
Salt River Project (SRP)
San Diego Gas & Electric Company
Santee Electric Cooperative Inc.
Sawnee Electric Membership Corporation
Shakopee Public Utilities Commission
Shelby Electric Cooperative
Shelby Energy Cooperative Inc.
Sioux Valley Southwestern Electric Cooperative, Inc.
Somerset Rural Electric Cooperative, Inc.
South Central Power Company
South Central Public Power District
Southeastern Electric Cooperative, Inc.
Southern California Edison
Southern Indiana Gas & Electric Co.
Southern Maryland Electric Cooperative, Inc.
Southside Electric Cooperative, Crewe,Virginia
Southwest Public Power District
Spring Valley Public Utilities
Steuben Rural Electric Cooperative, Inc.
Sullivan County Rural Electric Cooperative, Inc.
Sumter Electric Cooperative, Inc.
Sussex Rural Electric Cooperative, Inc.
Tampa Electric Company
The Caney Valley Electric Cooperative Assn., Inc.
The Detroit Edison Company
The Frontier Power Company
The Midwest Electric Cooperative Corporation
The Toledo Edison Co
Town of Ayden
Town of Edenton
Town of Frederick
Town of Massena
Tri-County Electric Membership Corporation
Tri-County Rural Electric Cooperative, Inc.
Union County Electric Cooperative, Inc.
United Electric Cooperative, Inc.
United Power, Inc
Verendrye Electric Cooperative, Inc.
Village of Arcade
Village of Genoa
Wabash Valley Power Assn, Inc.
White County REMC
White River Valley Electric Cooperative
Willmar Municipal Utilities
Wiregrass Electric Cooperative, Inc.
Wisconsin Power and Light Company
Wisconsin Public Service Corporation
Woodruff Electric Cooperative Corporation
Wright-Hennepin Cooperative Electric Association
XCEL d/b/a Northern States Power Co - Minnesota
XCEL d/b/a Northern States Power Co - Wisconsin
XCEL d/b/a Public Service Co of Colorado
XCEL d/b/a Southwestern Public Service Co

Emergency Demand Response

ALLETE Inc.
Blue Ridge Electric Membership Corporation
Borough of Weatherly, PA
CenterPoint Energy Houston Electric, LLC
City of Alpha
City of Anaheim
City of Columbia
Concord Municipal Utility
Delmarva Power & Light Company
Electric Reliability Council of Texas Inc.
Granite State Electric Company
Hess Corporation
Integrys Energy Services of New York, Inc.
ISO New England
Midwest ISO
Monongahela Power Company d/b/a Allegheny Power
Nebraska Public Power District

Emergency Demand Response (continued)

New Hampshire Electric Cooperative, Inc
New York Independent System Operator
New York Power Authority
Old Dominion Electric Cooperative
Pacific Gas and Electric Company
PECO Energy
PJM Interconnection, LLC
Potomac Edison Company d/b/a Allegheny Power
Rochester Gas & Electric Corporation
Sacramento Municipal Utility District
Southern California Edison
Suez Energy Resources North America
Tampa Electric Company
The Narragansett Electric Company
The United Illuminating Company
Town of Braintree Electric Light Department
Village of Minster
West Penn Power Company d/b/a Allegheny Power

Interruptible Load

Adams Electric Cooperative
Adams Electric Cooperative, Inc.
Adams-Columbia Electric Cooperative
Agralite Electric Cooperative
Alabama Power Company
Alcoa Power Generating, Inc.
Appalachian Power Company
Arkansas Electric Cooperative Corporation
Austin Utilities
Bluestem Electric Cooperative Inc.
Board of Public Utilities, City of McPherson
Boone Electric Cooperative
Brazos Electric Power Cooperative, Inc.
Brown County Rural Electrical Assn.
Brunswick Electric Membership Corporation
Buckeye Power, Inc.
Burlington Electric Department
California Independent System Operator
Central Electric Cooperative
Central Iowa Power Cooperative
Central Vermont Public Service Corporation
Cimarron Electric Cooperative
City of Cairo
City of Columbia
City of Lakeland, Lakeland Electric
City of Lincoln Electric System
City of Rock Hill
City of Saint Peter
City of Sheboygan Falls
City of Tallahassee
City of Washington
City of Winfield
City Utilities of Springfield
Clay Electric Cooperative, Inc.
Cleveland Electric Illuminating Co
Columbus Southern Power Company
Community Electric Cooperative
Connecticut Light and Power Co
Connexus Energy
Consolidated Edison Company of New York
Cooperative Light and Power Association
Corn Belt Energy Corporation
Cozad Board of Public Works
Cuivre River Electric Cooperative, Inc
Dairyland Power Cooperative
Dakota Electric Association
Dixie Escalante Rural Electric Association, Inc.
Duke Energy Corporation
El Paso Electric Company
Elk River Municipal Utilities - City of Elk River
Empire Direct Electric Company
Entergy Arkansas, Inc.
Entergy Louisiana, Inc.
Entergy Texas, Inc.
Farmers Electric Cooperative, Inc.
FEM Electric Association, Inc
First Electric Cooperative Corporation
Flint Electric Membership Corporation
Florida Power & Light, Co.
Four County Electric Membership Corporation
Fulton County Rural Electric Membership Corporation
Gainesville Regional Utilities
Georgia Power
Grand Marais Public Utilities
Green Mountain Power Corporation
Hawaiian Electric
H-D Electric Cooperative, Inc
High Plains Power Inc.
Horry Electric Cooperative, Inc.
Illinois Rural Electric Cooperative
Indiana Michigan Power Company
Indiana Municipal Power Agency
ISO New England
Itasca-Mantrap Cooperative Electrical Association
JEA
Kandiyohi Power Cooperative
Kansas City Power & Light Company
KCP&L Greater Missouri Operation Company
Kentucky Power Company
Lee County Electric Cooperative, Incorporated
Linn County Rural Electric Cooperative Association
Marshall Municipal Utilities
McLean Electric Cooperative, INC
McLeod Cooperative Power Association
Menard Electric Cooperative
Metropolitan Edison Co
MidAmerican Energy Company
Midwest ISO
Mille Lacs Energy Cooperative
Minnesota Municipal Power Agency
Minnesota Valley Electric Cooperative
Mississippi County Electric Cooperative , Inc.
Mississippi Power Company
Monongahela Power Company d/b/a Allegheny Power
Moorhead Public Service
Mountain View Electric Association, Inc.
NC Electric Membership Corp
Nobles Cooperative Electric
. North Arkansas Electric Cooperative, Incorporated

Interruptible Load (continued)

North Itasca Electric Cooperative Inc.
Northeastern REMC
Northern Indiana Public Service Co Northern Virginia Electric Cooperative
NorthWestern Energy
Northwestern Rural Electric Coop Association, Inc.
Nstar Electric
Ocmulgee Electric Membership Corporation
OGE Energy Corporation
Ohio Edison Co.
Ohio Power Company
Oklahoma Electric Cooperative
Omaha Public Power District
Osceola Electric Cooperative, Inc.
Ozark Border Electric Cooperative
Ozarks Electric Cooperative Corporation
Pacific Gas and Electric Company
Palmetto Electric Cooperative, Inc.
PECO Energy
Pennsylvania Electric Co
Potomac Edison Company d/b/a Allegheny Power
PPL Electric Utilities
Prince George Electric Cooperative
Progress Energy Carolinas
Progress Energy Florida
Public Service Co of NH
Public Service Company of Oklahoma
Public Service Electric & Gas Company
Rappahannock Electric Cooperative
Red River Valley Rural Electric Association
Rochester Public Utilities
Roughrider Electric Cooperative, Inc.
Sacramento Municipal Utility District
Salt River Electric Coop Corp
Salt River Project (SRP)
San Diego Gas & Electric Company
Satilla Rural Electric Membership Corporation
SEMO Electric Cooperative
Shelby Electric Cooperative
Shelby Energy Cooperative Inc.
Shenandoah Valley Electric Cooperative
Sierra Pacific Power Company
South Carolina Electric & Gas Company
South Carolina Public Service Authority
South Central Arkansas Electric Cooperative, Inc.
South Kentucky Rural Electric Cooperative Corp
Southern California Edison
Southern Indiana Gas & Electric Co.
Southside Electric Cooperative, Crewe,Virginia
Southwest Arkansas Electric Cooperative Corporation
Southwest Rural Electric Association
Southwestern Electric Power Company
Spencer Municipal Utilities
Suez Energy Resources North America
Sumter Electric Cooperative, Inc.
Sussex Rural Electric Cooperative, Inc.
Tampa Electric Company
Tennessee Valley Authority
The Detroit Edison Company
The Toledo Edison Co
Tri-County Electric Membership Corporation
Union County Electric Cooperative, Inc.
United Electric Cooperative, Inc.
Upper Peninsula Power Company
Village of Minster
Wabash Valley Power Assn, Inc.
Warren Electric Cooperative, Inc.
Webster Electric Cooperative
West Penn Power Company d/b/a Allegheny Power
Western Farmers Electric Cooperative
Wheeling Power Company
Willmar Municipal Utilities
Wisconsin Power and Light Company
Wisconsin Public Service Corporation
Woodruff Electric Cooperative Corporation
WPPI Energy
Wright-Hennepin Cooperative Electric Association
XCEL d/b/a Northern States Power Co - Minnesota
XCEL d/b/a Northern States Power Co - Wisconsin
XCEL d/b/a Public Service Co of Colorado
XCEL d/b/a Southwestern Public Service Co

Load as a Capacity Resource

Adams Electric Cooperative, Inc.
Bedford Rural Electric Cooperative, Inc.
Bluebonnet Electric Cooperative, Inc.
Cass County Electric Cooperative
Central Electric Cooperative, Inc.
Claverack Rural Electric Cooperative, Inc.
Commonwealth Edison Company
Comperio Energy LLC, d/b/a ClearChoice Energy
Dow Hydrocarbons and Resources, LLC
Galt Power
Indianapolis Power & Light Company
Midwest ISO
New York Electric & Gas Corporation
New York Independent System Operator
New York Power Authority
Northwestern Rural Electric Coop Association, Inc.
Pacific Gas and Electric Company
REA Energy Cooperative, Inc.
Rochester Gas & Electric Corporation
Somerset Rural Electric Cooperative, Inc.
Southern California Edison
Southern Minnesota Municipal Power Agency
Sullivan County Rural Electric Cooperative, Inc.
Sussex Rural Electric Cooperative, Inc.
Tampa Electric Company
Town of Ayden
Tri-County Electric Cooperative, Inc
Tri-County Rural Electric Cooperative, Inc.
United Electric Cooperative, Inc.
Valley Rural Electric Cooperative, Inc.
Virtual Energy LLC
Wabash Valley Power Assn, Inc.
Wellesley Municipal Light Plant
Wisconsin Electric Power Company
WPPI Energy

Non-Spinning Reserve

PJM Interconnection, LLC
Electric Reliability Council of Texas Inc.
PacifiCorp

Other

Agralite Electric Cooperative
Alabama Power Company
ALLETE Inc.
Arizona Public Service Company
Boone Electric Cooperative
Brown County Rural Electrical Assn.
Brunswick Electric Membership Corporation
City of Groton
City of Monroe, NC
City of Northwood Utilities
City of Radford
City of Salem
City of Thomasville
City of Vermillion
Commonwealth Edison Company
Cozad Board of Public Works
Dakota Electric Association
Dixie Escalante Rural Electric Association, Inc.
Electrical Dist No3 Pinal Cnty
Escambia River Electric Cooperative
Four County Electric Membership Corporation
Great River Energy
Illinois Rural Electric Cooperative
Itasca-Mantrap Cooperative Electrical Association
Kandiyohi Power Cooperative
Kansas City Power & Light Company
KCP&L Greater Missouri Operation Company
Laurens Commission of Public Works
Minnesota Valley Electric Cooperative
Nebraska Public Power District
New York Independent System Operator
Niagara Mohawk Power Corporation
North Central Power Co., Inc.
Northern Indiana Public Service Co.
Ocmulgee Electric Membership Corporation
Puget Sound Energy, Inc.
Salt River Project (SRP)
Sawnee Electric Membership Corporation
Sierra Electric Cooperative, Inc.
South Carolina Electric & Gas Company
Southern California Edison
Southwest Power Pool, Inc
Spring Valley Public Utilities
Tennessee Valley Authority
Town of Ayden
United Electric Coop Services
Village of Decatur
Wisconsin Electric Power Company
Withlacoochee River Electric Cooperative, Inc.

Peak Time Rebate

Austin Energy
Baltimore Gas and Electric Company
Central Vermont Public Service Corporation
City of Laurinburg
City of Thomasville
Elk River Municipal Utilities - City of Elk River
Granite State Electric Company
Grundy Electric Cooperative, Inc.
Massachusetts Electric Company
Nantucket Electric Company
OGE Energy Corporation
Potomac Electric Power Company
The Narragansett Electric Company
Union Electric Company

Real-Time Pricing

Alpena Power Company
Central Hudson Gas & Electric Corporation
Commonwealth Edison Company
Crisp County Power Commission
Duke Energy Corporation
Georgia Power
Gulf Power Company
Indiana Michigan Power Company
Kansas City Power & Light Company
KCP&L Greater Missouri Operation Company
Kentucky Power Company
MidAmerican Energy Company
New Hampshire Electric Cooperative, Inc
Nstar Electric
OGE Energy Corporation
Otter Tail Power Co.
PJM Interconnection, LLC
Potomac Edison Company d/b/a Allegheny Power
Progress Energy Carolinas
Public Service Company of Oklahoma
Public Service Electric & Gas Company
South Carolina Public Service Authority
Southern California Edison
Wheatland Electric Cooperative, Inc.
XCEL d/b/a Northern States Power Co - Minnesota
XCEL d/b/a Northern States Power Co - Wisconsin

Regulation

Electric Reliability Council of Texas Inc.
PJM Interconnection, LLC
Tanana Power Company

Spinning Reserves

Electric Reliability Council of Texas Inc.
Galt Power
PJM Interconnection, LLC

System Peak Response Transmission Tariff

Habersham Electric Membership Corporation
Red River Valley Rural Electric Association

Time-of-Use

A & N Electric Cooperative
Adams Electric Cooperative
Adams Electric Cooperative, Inc.
Adams-Columbia Electric Cooperative
Algoma Utility Commission
Appalachian Power Company
Arizona Public Service Company
Bangor Hydro Electric Company
Bear Valley Electric Service
Big Horn Rural Electric
Black River Falls Municipal Electric & Water
Board of Public Utilities, City of McPherson
Brodhead Water & Light Commission
Burlington Electric Department
Butler County Rural Electric Cooperative
Carbon Power & Light Inc
Carteret-Craven Electric Membership Corporation
Cedarburg Light & Water Commission
Central Florida Electric Cooperative, Inc.
Central Hudson Gas & Electric Corporation
Central Vermont Public Service Corporation
Choptank Electric Cooperative, Inc.
City of Boulder City
City of Carlyle
City of Columbia
City of Crystal Falls
City of Denton
City of Detroit
City of Forest Grove Light and Power
City of Gastonia
City of Glendale
City of Gothenburg
City of Lakeland, Lakeland Electric
City of Marshfield
City of Medford
City of Palo Alto Utilities
City of Rancho Cucamonga
City of Redding Electric Utility
City of Roseville
City of Salem
City of Westfield
Clark County Rural E M C
Claverack Rural Electric Cooperative, Inc.
Clay Electric Cooperative, Inc.
Coast Electric Power Association
Colorado River Commission of Nevada
Columbus Southern Power Company
Columbus Water & Light Dept.
Connecticut Light and Power Co
Consumers Energy Cooperative
Coweta-Fayette EMC
Crawfordsville Electric Light & Power
Crisp County Power Commission
Crow Wing Cooperative Power & Light Company
Cuba City Electric & Water Utility
Dairyland Power Cooperative
Delmarva Power & Light Company
Delta Electric Power Association
Denton County Electric Cooperative, Inc.
Direct Energy Business, LLC (fka Strategic Energy, LLC)
Direct Energy Services, LLC
Duke Energy Corporation
Eagle River Light & Water Commission
El Paso Electric Company
Electrical Dist No3 Pinal Cnty
Empire Direct Electric Company
Energetix, Inc.
Entergy Arkansas, Inc.
Entergy Louisiana, Inc.
Entergy Texas, Inc.
Evansville Water & Light
Fitchburg Gas and Electric Light Company
Flathead Electric Cooperative, Inc.
Florence Utility Commission
Florida Power & Light, Co.
Four County Electric Membership Corporation
Gaffney Board of Public Works
Gainesville Regional Utilities
Georgia Power
Grand Haven Board of Light and Power
Grand River Dam Authority
Granite State Electric Company
Green Mountain Power Corporation
Groton Electric Light
Gulf Power Company
Hartford Utilities
Heart of Texas Electric Cooperative
Hendricks County Rural Electric Membership Coop
Highline Electric Association
Holy Cross Energy
Hustisford Utilities
Idaho Power Company
Indiana Michigan Power Company
Interstate Power and Light Company
Jackson Electric Cooperative, Inc
Jackson Electric Membership Corporation
Jefferson Water & Light Dept.
Jemez Mountains Electric Cooperative, Inc.
Jo-Carroll Energy, Inc.(NFP)
Johnson County REMC
Juneau Utility Commission
Kansas City Power & Light Company
Kaukauna Utilities
KCP&L Greater Missouri Operation Company
Kentucky Power Company
Kiamichi Electric Cooperative, Inc
Kingsport Power Company
La Plata Electric Association, Inc.
Lake Mills Light & Water Dept.
Laurens Commission of Public Works
Linn County Rural Electric Cooperative Association
Lodi Municipal Light & Water Utility
Long Island Power Authority
Los Angeles Department of Water and Power
Magic Valley Electric Cooperative, Inc.
Maquoketa Valley REC
Maui Electric Company, Ltd
McLeod Cooperative Power Association
Mecklenburg Electric Cooperative
Menasha Electric & Water Utilities
MidAmerican Energy Company
Midwest Energy, Inc.

Time-of-Use (continued)

Minnesota Municipal Power Agency
Mississippi Power Company
Moon Lake Electric Assn. Inc.
Mount Horeb Electric Utility
Mountain Parks Electric, Inc.
Mountain View Electric Association, Inc.
Muscoda Light & Water Utility
Nebraska Public Power District
Nevada Power Company
New Glarus Light & Water Works
New Hampshire Electric Cooperative, Inc
New Holstein Public Utility
New London Electric & Water Utility
New Richmond Municipal Electric Utility
New York State Electric & Gas Corporation
Noble County REMC
North Central Power Co., Inc.
Northern Neck Electric Cooperative
Northern Rio Arriba Electric Coop., Inc.
Northwest Rural Public Power District
NorthWestern Energy
Northwestern Rural Electric Coop Association, Inc.
NYSEG Solutions, Inc.
Oconomowoc Utilities
Oconto Falls Water & Light Commission
OGE Energy Corporation
Ohio Power Company
Okefenoke Rural El Member Corp
Oklahoma Electric Cooperative
Orlando Utilities Commission
Otero County Electric Cooperative, Inc.
Otsego Electric Cooperative, Inc.
Otter Tail Power Co.
Pacific Gas and Electric Company
Palmetto Electric Cooperative, Inc.
Pee Dee Electric Cooperative, Inc.
Pee Dee Electric Membership Corp.
Piedmont Electric Membership Corporation
Plymouth Utilities
Potomac Electric Power Company
Poudre Valley Rural Electric Association
Powder River Energy Corporation
Prairie du Sac Municipal Electric & Water
Progress Energy Carolinas
Progress Energy Florida
Public Service Co of NH
Public Service Company of Oklahoma
Public Service Electric & Gas Company
PUD No 1 of Clark County
Red River Valley Rural Electric Association
Reedsburg Utility Commission
Rice Lake Utilities
Richland Center Electric Utility
Richmond Power and Light
River Falls Municipal Utility
Riverside Public Utilities
Sacramento Municipal Utility District
Salt River Electric Coop Corp
Salt River Project (SRP)
San Luis Valley REC
Satilla Rural Electric Membership Corporation
Sawnee Electric Membership Corporation
Sierra Electric Cooperative, Inc.
Sierra Pacific Power Company
Silicon Valley Power
Singing River Electric Power Association
Slinger Utilities
Snohomish County Public Utility District #1
Somerset Rural Electric Cooperative, Inc.
South Carolina Electric & Gas Company
South Carolina Public Service Authority
South Kentucky Rural Electric Cooperative Corp
South Mississippi Electric Power Association
Southeast Colorado Power Association
Southern California Edison
Southwest Louisiana Electric Membership Corp
Southwest Rural Electric Association
Southwestern Electric Cooperative, Inc.
Southwestern Electric Power Company
Spooner, City of
Steuben Rural Electric Cooperative, Inc.
Stoughton Electric Utility
Sturgeon Bay Utilities
Sullivan County Rural Electric Cooperative, Inc.
Sun Prairie Water & Light Commission
Sussex Rural Electric Cooperative, Inc.
Suwannee Valley Electric Cooperative, Inc.
Tampa Electric Company
Taylor Electric Cooperative
Tri-County Electric Cooperative, Inc
Tucson Electric Power Co.
Two Rivers Water & Light Utility
TXU Energy Retail Company LLC
Union Electric Company
United Electric Coop Services
United Power, Inc
Valley Rural Electric Cooperative, Inc.
Verdigris Valley Electric Cooperative, Inc
Village of Greenport
Village of Stratford
Warren Electric Cooperative, Inc.
Washington-St.Tammany Electric Cooperative, Inc.
Waterloo Water & Light Commission
Waunakee Water & Light Commission
Waupun Public Utilities
West River Electric Association, Inc.
Westby Municipal Electric Utility
Western Massachusetts Elec Co
Wheatland Electric Cooperative, Inc.
Wheeling Power Company
Whitehall Municipal Electric Utility
Willmar Municipal Utilities
Wisconsin Power and Light Company
Wisconsin Public Service Corporation
WPPI Energy
Wyrulec Company
XCEL d/b/a Northern States Power Co - Minnesota
XCEL d/b/a Northern States Power Co - Wisconsin
Yazoo Valley Electric Power Association

Appendix G: Data for Figures in the Report

Appendix G provides the numerical data used to create the figures in the 2010 FERC Assessment of Demand Response and Advanced Metering, and the sources of the data. The data is this appendix, where compiled directly from data submitted by survey respondents without estimation of results for those not reporting, are labeled “Reported” or “Reporting.” Data that include estimation of results for those not reporting, based on survey and other information, are labeled “Estimated.”

Advanced Metering

Data supporting Figure 3.1

Estimated advanced metering penetration nationwide in 2006, 2008 and 2010 FERC Surveys

Year	Advanced Metering
2010	5.9%
2008	4.7%
2010	8.7%

Source: 2006, 2008 and 2010 FERC Surveys

Data supporting Figure 3.2

Estimated advanced metering penetration by region in 2006, 2008 and 2010 FERC Surveys

Region	2006 FERC Survey	2008 FERC Survey	2010 FERC Survey
MRO	0.6%	3.7%	15.3%
WECC	0.5%	2.1%	14.1%
ERCOT (TRE)	0.7%	9.0%	13.4%
SPP	3.0%	5.8%	8.9%
SERC	1.2%	5.8%	8.0%
RFC	0.4%	5.1%	6.7%
FRCC	0.1%	10.4%	5.0%
Hawaii	0.0%	1.6%	2.1%
ASCC	0.0%	0.0%	1.2%
NPCC	0.1%	0.3%	0.7%
United States	0.7%	4.7%	8.7%

Source: 2006, 2008 and 2010 FERC Surveys

Data supporting Figure 3.3

Estimated penetration of advanced metering by type of entity in 2006, 2008 and 2010 FERC Surveys

Ownership	2006 FERC Survey	2008 FERC Survey	2010 FERC Survey
Cooperatives	3.8%	16.4%	24.7%
Political Subdivision	0.1%	2.2%	20.3%
Investor Owned Utility	0.2%	2.7%	6.6%
Municipal Entities	0.3%	4.9%	3.6%
Federal and State Utility	0.2%	1.1%	0.7%
Overall Average	0.7%	4.7%	8.7%

Source: 2006, 2008 and 2010 FERC Surveys

Data supporting Figure 3.4

Reported numbers of customers and communication methods for advanced metering by customer class

Customer Class	Internet	Bills	Display Unit
Communications Vehicles to Nonresidential Customers (n = 915,726)	61% (n = 560,452)	38% (n = 346,750)	1% (n = 8,524)
Communications Vehicles to Residential Customers (n = 7,093,081)	68% (n = 4,819,498)	31% (n = 2,186,869)	1% (n = 86,714)
Communications Vehicles to Other Customers (n = 52,812)	47% (n = 24,664)	53% (n = 27,959)	.36% (n = 189)

Source: 2010 FERC Survey

Demand Response

Data supporting Figure 4.1

Reported number of customers enrolled in direct load control programs by region and type of entity

Region	Cooperative Entities	Federal and State	Investor Owned Utilities	Municipal Entities	Other	Total
TRE				85,000	171	85,171
FRCC	60,588		1,247,228			1,307,816
MRO	406,632	2,365	507,152	48,849		964,998
NPCC	6,261		39,634	32,660		78,555
RFC	294,278		1,203,367	2,270		1,499,915
SERC	421,625		347,748	29,577		798,950
SPP	13,119		35,479			48,598
WECC	4,602		821,610	6,872		833,084
Other			39,000			39,000
Total	1,207,105	2,365	4,241,218	205,228	171	5,656,087

Source: 2010 FERC Survey

Estimated total number of customers

TRE	FRCC	MRO	NPCC	RFC	SERC	SPP	WECC	Other
11,242,472	9,001,379	7,694,462	16,062,605	36,257,770	31,682,323	6,509,331	31,044,502	683,840

Source: 2008 FERC Survey, EIA-861

Data supporting Figure 4.2

Number of entities reporting interruptible/curtailable rates by region and type of entity

Region	Cooperative Entities	Federal and State	Investor Owned Utilities	Municipal Entities	Other	Total
TRE	1	0	0	0	1	2
FRCC	3	0	3	5	0	11
MRO	37	0	13	12	0	62
NPCC	0	0	6	1	0	7
RFC	14	0	46	1	0	61
SERC	31	9	29	3	0	72
SPP	9	0	10	4	0	23
WECC	8	0	17	2	0	27
Total	103	9	124	28	1	265

Source: 2010 FERC Survey

Data supporting Figure 4.3

Number of entities reporting residential time-of-use rates by region and type of entity

Region	Cooperative Entities	Federal and State	Investor Owned Utilities	Municipal Entities	Other	Total
TRE	1	0	0	0	0	1
FRCC	2	0	2	3	0	7
MRO	8	0	3	35	0	46
NPCC	3	0	9	4	3	19
RFC	10	0	23	1	0	34
SERC	12	1	10	0	0	23
SPP	3	0	1	0	0	4
WECC	19	0	12	5	0	36
Total	58	1	60	48	3	169

Source: 2010 FERC Survey

Data supporting Figure 4.4

Reported number of customers enrolled in time-of-use rate programs by region and type of entity

Region	Cooperative Entities	Federal and State	Investor Owned Utilities	Municipal Entities	Other	Total
TRE	8	0	0	0	0	8
FRCC	40	0	249	206	0	495
MRO	1,546	0	20,387	284	0	22,217
NPCC	63	0	148,706	10,152	148	159,069
RFC	1,521	0	138,910	0	0	140,431
SERC	3,289	5	33,301	0	0	36,595
SPP	15	0	1,452	0	0	1,467
WECC	237,187	0	498,477	2,388	0	738,052
Total	243,669	5	841,482	13,030	148	1,098,334

Source: 2010 FERC Survey

Data supporting Figure 4.5

Number of entities reporting retail real-time pricing by region & type of entity

Region	Cooperative Entities	Federal and State	Investor Owned Utilities	Total
TRE	0	0	0	0
FRCC	0	0	0	0
MRO	0	0	1	1
NPCC	1	0	2	3
RFC	0	0	6	6
SERC	1	2	3	6
SPP	0	0	2	2
WECC	0	0	1	1
Total	2	2	15	19

Source: 2010 FERC Survey

Data supporting Figure 4.6

Total reported potential peak load reduction in the 2006, 2008 and 2010 FERC Surveys

	Total reported potential peak load reduction (MW)
2006 FERC Survey	29,653
2008 FERC Survey	37,335
2010 FERC Survey	53,062

Source: 2006, 2008 and 2010 FERC Surveys

Data supporting Figure 4.7

Reported potential peak load reduction by customer class in 2006, 2008, and 2010 FERC Surveys (MW)

	Commercial & Industrial	Residential	Wholesale	Other	Total
2006 FERC Survey	14,362	5,803	8,899	589	29,653
2008 FERC Survey	17,434	6,056	12,656	1,190	37,335
2010 FERC Survey	21,405	7,189	22,884	1,584	53,062

Source: 2006, 2008 and 2010 FERC Surveys

Data supporting Figure 4.8

Reported potential peak load reduction in MW by region and customer class

Region	Commercial & Industrial	Residential	Wholesale	Other	Total
TRE	72	123	1,312	3	1,510
FRCC	1,310	1,765	15	68	3,158
MRO	3,320	1,806	4,045	315	9,485
NPCC	1,490	90	4,649	0	6,228
RFC	5,267	1,139	9,199	259	15,864
SERC	6,451	798	1,733	172	9,154
SPP	1,404	79	1,502	141	3,126
WECC	2,062	1,369	430	626	4,487
Other	29	20	0	0	49
Total	21,405	7,189	22,884	1,584	53,062

Source: 2010 FERC Survey

Data supporting Figure 4.9

Reported potential peak load reduction in MW by type of program and by customer class

Type of Program	Commercial and Industrial	Residential	Wholesale	Other	Total
Critical Peak Pricing	401	30	100	88	619
Critical Peak Pricing with Load Control	129	8	0	13	149
Demand Bidding & Buy-Back	1,251	0	2,750	17	4,018
Direct Load Control	1,687	5,568	793	957	9,006
Emergency Demand Response	1,375	163	11,493	11	13,041
Interruptible Load	9,524	50	1,033	371	10,977
Load as a Capacity Resource	3,503	1,124	4,110	53	8,790
Non-Spinning Reserves	-	-	118	-	118
Other	151	134	1,000	56	1,340
Peak Time Rebate	90	4	0		94
Real-Time Pricing	1,117	4	0	0	1,121
Regulation	-	-	10	-	10
Spinning Reserves	46	-	1,442	-	1,488
System Peak Response Transmission Tariff	1	4	0	-	5
Time-of-Use	2,132	100	35	19	2,285
Total	21,405	7,189	22,884	1,584	53,062

Source: 2010 FERC Survey

Data supporting Figure 4.10

Net annual U.S. electrical generation, 2005 through 2009 (thousands of megawatt-hours)

Year	Net annual U.S. electrical generation
2005	4,055,423
2006	4,064,702
2007	4,156,745
2008	4,119,388
2009	3,953,111

Source: Energy Information Administration

Data supporting Figure 4.11

Reported potential and actual 2010 peak load reduction in MW by demand response resources by region

Region	Potential Peak Reduction	Actual Peak Reduction
TRE	1,510	442
FRCC	3,158	957
MRO	9,485	2,462
NPCC	6,228	2,497
RFC	15,864	2,051
SERC	9,154	3,086
SPP	3,126	1,466
WECC	4,487	2,667
Other	49	352
Total	53,062	15,980

Source: 2010 FERC Survey

Data supporting Figure 4.12

Estimated potential peak load reduction in MW by demand response resources, by region and customer class

Region	Commercial & Industrial	Residential	Wholesale	Other	Total
TRE	113	134	1,312	53	1,612
FRCC	1,333	1,795	15	73	3,216
MRO	3,932	2,102	4,045	339	10,418
NPCC	1,954	98	4,649	173	6,875
RFC	6,334	1,427	9,199	371	17,331
SERC	7,005	1,575	1,733	208	10,521
SPP	1,572	80	1,502	154	3,307
WECC	2,344	1,581	430	626	4,981
Other	53	25			78
Total	24,640	8,817	22,884	1,998	58,339

Source: 2010 FERC Survey

Data supporting Figure 4.13

Estimated potential peak load reduction in MW by demand response resources by type of entity and customer class

Ownership	Residential	Commercial & Industrial	Other Retail	Wholesale	Total
Investor Owned Utilities	5,433	17,634	827	0	23,894
Cooperative Entities	2,836	3,726	855	1,420	8,837
Municipal Entities	530	922	25	11	1,488
Retail Power Marketers	0	961	241	0	1,202
Federal & State	17	1,104	50	920	2,091
RTO/ISO				20,533	20,533
Total	8,816	24,347	1,998	22,884	58,045

Source: 2010 FERC Survey

APPENDIX H: ADJUSTMENT METHODOLOGY FOR 2010 FERC SURVEY

The following table summarizes the data used for imputing missing 2010 data in fields involved in the tables and figures in this report, as described in Appendix D.

Table H1. Sources of data used to impute missing 2010 FERC survey data

2010 Field	Sector	Comparison Survey	Comparison Survey Fields	Sort Variable
Meters	Residential	2008 EIA-861 file 2	RESIDENTIAL_CONSUMERS	Residential Revenues
Meters	Commercial & Industrial	2008 EIA-861 file 2	COMMERCIAL_CONSUMERS, INDUSTRIAL_CONSUMERS	C & I Revenues
Meters	Other	2008 FERC DR Survey	Q7-OtherMeters	Size
Customers	Residential	2008 EIA-861 file 2	RESIDENTIAL_CONSUMERS	Residential Revenues
Customers	Commercial & Industrial	2008 EIA-861 file 2	COMMERCIAL_CONSUMERS, INDUSTRIAL_CONSUMERS	C & I Revenues
Customers	Other	2008 FERC DR Survey	Q7-OtherMeters	Size
AMI Meters	Residential	2008 EIA-861 file 8	AMI_METERING_RESIDENTIAL	Residential Revenues
AMI Meters	Commercial & Industrial	2008 EIA-861 file 8	AMI_METERING_COMMERCIAL, AMI_METERING, INDUSTRIAL	C & I Revenues
AMI Meters	Other	2008 FERC DR Survey	Q8-15Min-OtherAMI, Q8-Hourly-OtherAMI	Size
DR Program Customers	Residential	2008 EIA-861 file 3	PRICERESPRES, TIMERESPRES	Residential Retail Sales
DR Program Customers	Commercial & Industrial	2008 EIA-861 file 3	PRICERESPCOM, PRICERESPIND, TIMERESPCOM, TIMERESPIND	C & I Retail Sales
DR Program Customers	Other	2008 EIA-861 file 3	Nbr_cust_enrolled	Nbr_cust_in_Class
DR Program Customers	DLC Program - Residential	2008 FERC DR Survey	Nbr_Cust_Enrolled	Nbr_Cust_in_Class
DR Program Customers	TOU Program - Residential	2008 FERC DR Survey	Nbr_Cust_Enrolled	Nbr_Cust_in_Class
Potential DR Peak Reduction	Residential	2008 EIA-861 file 3	LMPOTENTPEAKREDANNRES	Residential Retail Sales
Potential DR Peak Reduction	Commercial & Industrial	2008 EIA-861 file 3	LMPOTENTPEAKREDANNCOM, LMPOTENTPEAKREDANNIND	C & I Retail Sales
Potential DR Peak Reduction	Other	2008 FERC DR Survey	Potential_Peak_Red	Not Used
Actual DR Peak Reduction	Residential	2008 EIA-861 file 3	LMACTUALPEAKREDANNRES	Residential Retail Sales
Actual DR Peak Reduction	Commercial & Industrial	2008 EIA-861 file 3	LMACTUALPEAKREDANNCOM, LMACTUALPEAKREDANNIND	C & I Retail Sales
Actual DR Peak Reduction	Other	2008 FERC DR Survey	Actual_Peak_Red	Not Used

The steps for producing the imputed values for the nonrespondent entities were as follows:

Step 1: Merge comparison survey variables to 2010 FERC data at the level needed for the analysis tables and figures. There are four possible response cases for entities in the merged data sets:

1) Entity provided a response in both 2010 and the 2008 comparison survey field
2) Entity provided a response in 2010 but not in the 2008 comparison survey field
3) Entity provided no response in 2010 but provided a response in the 2008 comparison survey field
4) Entity responded in neither 2010 nor the 2008 comparison survey field

Step 2: Isolate the entities in case 1 above and compute the percent increase from the comparison survey field and the 2010 variable.
Step 3: Subset further, keeping just the entities with a percent increase between -50 and +100 (so the 2010 value was between half and twice that of the 2008 comparison value).
Step 4: Assign a size variable to small, medium, or large depending on the value of the sort variable. Add this to the step 3 data set.
Small: sort variable in the first quartile of the step 3 subset
Medium: sort variable between the first and third quartiles of the step 3 subset
Large: sort variable greater than the third quartile of the step 3 subset
Step 5: Plot the 2010 variable against the 2008 comparison survey variable by size category to check for linearity.
Step 6: When sufficient data exists, fit a linear regression of the 2010 variable on the comparison survey field with no intercept for each size category.
Step 7: Merge the three size category regression coefficients onto the step 1 data set according to the size of the sort variable, i.e. medium sized entities will be assigned the regression coefficient fit for the medium sized entities.
Step 8: For the case 3 entities in step 1 above, assign the 2010 value as follows:
2010 value = 2008 comparison survey field * regression coefficient
Each of these case 3 entities is assigned an imputation flag.

Self-Selection Assessment Subsample

Commission staff determined that the FERC Survey, to adhere with its EPAct 2005 directive, must collect information on all entities that provide electric power and demand response to customers in the U.S. The FERC Survey population, essentially a census of respondents to the EIA-861 with the addition of Regional Transmission Operators (RTOs), Independent System Operators (ISOs), and Curtailment Service Providers (CSPs), is a voluntary survey. As such, there is inherent risk of self-selection bias – some subgroups of the entities asked to respond to the FERC Survey may be more likely to respond than others and the propensity for responding may be related to key measures in the FERC Survey such as advanced metering penetration.

The role of the subsample is to establish a subset of the full FERC Survey sample from which a set of survey response rates, subject to less risk of self-selection bias, may be used to compare against the corresponding set of response rates in the complementary portion of the main survey sample for which no special measures were taken to reduce the risk of self-selection bias. Significant differences in corresponding response rates would indicate that there is risk of self-selection bias in the full set of respondents to the FERC Survey.

While the Commission designed the survey instrument and collection process with the goal of obtaining a survey response from every targeted electricity providing entity, this subsample was targeted for follow-up measures such as callbacks to achieve as high a response rate as possible given the resource constraints of the survey and time constraints for reporting results. This extensive follow-up effort reaches out to potential respondents who chose not to respond for any number of reasons with the goal of obtaining responses by assisting them in filling out the form, explaining the purpose of the survey, and accommodating their wishes to complete the survey form by some other means.

2006 and 2008 Subsample Designs

In 2006 the FERC Survey was approved as a census with the following terms and conditions: "OMB approves this collection for one year with the following terms of clearance: FERC has agreed to several changes to its survey design to mitigate the potential for self-selection bias and will draw a random sample of 776 for follow-up to ensure a representative sample for the advanced metering survey. FERC will report back to OMB on achieved response rates by strata and on the results of analyses comparing the random sample to the universe of responses. FERC will also note any meaningful differences in its final report to Congress."

Commission expert knowledge of advanced metering penetration led the sample to be stratified into groups of similar entities rather than a simple random sample from the full frame. The attributes stratifying the sample population into cells of similar entities were NERC region, type of utility, and the number of retail customers served which are then grouped into size categories as follows:

- Large – 100,000 or more customers
- Medium – more than 25,000 and fewer than 100,000 customers
- Small – 25,000 or fewer customers
- Non-Retail – Entities that do not serve retail customers directly

2010 Subsample Design

The same basic subsample design as was used in 2006 and 2008 was maintained for the 2010 FERC Survey, with some modifications.

- Entities continued to be stratified by utility type and region, but unlike 2006 and 2008, not according to the small, medium, and large categories. In 2010 the total number of customers will be used as the measure-of-size variable to select the uncertain portion of the sample via stratified ratio estimation assuming a very weak association between number of customers and advanced metering penetration.

- A subset of the frame will be selected as a simple random sample rather than using the number of consumers as a measure of size. This subset will consist of entities for which the frame lacks information for NERC region and total number of consumers. These entities cannot be selected using the method above because they do not have the strata fields or the measure-of-size needed for selection.

- The following NERC Regions plus Alaska and Hawaii, as well as split regions composed of them, will be considered in scope for the sample:
    - AK
    - FRCC
    - HI
    - MRO
    - NPCC
    - RFC (formerly MAAC, MAIN, and ECAR)
    - SERC
    - SPP
    - TRE
    - WECC

- The following entity types will be considered in scope for the sample:
    - Co-operative
    - CSP
    - Federal
    - IOU
    - Municipal
    - Municipal Power Authority
    - Political Subdivision
    - Retail Power Marketer
    - State
    - ISO/RTO

- The total sample size was fixed at 700.

- Stratified simple random sample – 50 from list of 461 entities meeting the following criteria:
  - Fewer than 10 consumers or none listed on the frame
  - Municipal Marketing Authorities
  - Cross-listed between NERC regions
- The sample of 50 will be stratified by ownership and drawn using proportional allocation.

- Stratified Ratio Estimation – 650 (from 2925 entities in NERC/ownership and size strata)

Entities were selected at random within ownership type/regional strata, with minimum strata sample sizes constrained to three or more entities. If a region/ownership group has just one or two entities, they were selected with certainty.

The stratified ratio estimation splits the strata further into small, medium, and large groups with the cutoffs for each size group determined by the sampling algorithm. Within the ultimate strata cells, the sampling algorithm selects entities with probability proportionate to their size, so the entity with the most consumers within an ownership type/region/size cell will have a greater chance of being selected than the other entities in the cell. Although the size categories for the sample strata will not have fixed cutoff levels, the response rates will be reported according to the size categories used in 2006 and 2008 for consistency with prior reports.

Additional follow-ups outside the 700 entities in the sample were carried out for nonresponding entities in order to achieve the highest possible overall response rate. The follow-up effort utilized a list of all entities in the mail-out, ordered according to their relative priority for obtaining a response. The ordered list was organized in three tiers. The top tiers consisted of entities serving 100,000 or more consumers, ISOs, RTOs, or have and entities having State or Federal ownership. The middle tier consisted of entities serving between 25,000 and 100,000 consumers, and the final tier the remaining entities. Within each tier the entities were assigned a random order so that the follow-up effort was not biased by ownership type within the respective tiers. The follow-up was done first focusing completely on the top tier, then moving to the middle tier, and finally the third tier.

Table H2. Subsample response rates

Type of Entity	Size	Total Number	DR Sample Response Rate (n=940)	DR Actual Response Rate (n=537)	AMI Sample Response Rate (n=2183)	AMI Actual Response Rate (n=1746)	Overall Sample Response Rate (n=2182)	Overall Actual Response Rate (n=1755)
Cooperatively Owned Utility	Large	23	63.6%	60.9%	72.7%	69.6%	72.7%	69.6%
	Medium	188	40.7%	38.3%	81.3%	74.5%	81.3%	74.5%
	Other	47	0.0%	21.3%	80.0%	55.3%	80.0%	59.6%
	Small	620	25.7%	21.9%	67.6%	61.9%	68.6%	62.1%
Curtailment Service Provider	Other	11	0.0%	9.1%	50.0%	18.2%	50.0%	18.2%
Federal and State Utility	Large	2	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
	Medium	1	0.0%	0.0%	100.0%	100.0%	100.0%	100.0%
	Other	16	0.0%	6.3%	50.0%	62.5%	50.0%	62.5%
	Small	10	37.5%	30.0%	87.5%	90.0%	87.5%	90.0%
Investor Owned Utility	Large	114	79.8%	76.3%	96.2%	94.7%	96.2%	94.7%
	Medium	22	40.0%	40.9%	80.0%	77.3%	80.0%	77.3%
	Other	27	0.0%	0.0%	0.0%	14.8%	0.0%	18.5%
	Small	44	14.3%	11.4%	60.7%	52.3%	60.7%	52.3%
Municipally Owned Utility	Large	20	50.0%	50.0%	83.3%	85.0%	83.3%	85.0%
	Medium	87	19.6%	14.9%	66.7%	59.8%	66.7%	59.8%
	Other	21	0.0%	19.0%	100.0%	57.1%	100.0%	57.1%
	Small	1733	3.4%	6.8%	55.9%	45.3%	55.9%	45.5%
Other	Medium	1	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Other	53	0.0%	0.0%	10.0%	3.8%	10.0%	3.8%
	Small	3	0.0%	100.0%	0.0%	100.0%	0.0%	100.0%
Political Subdivision	Large	7	71.4%	71.4%	85.7%	85.7%	85.7%	85.7%
	Medium	12	8.3%	8.3%	66.7%	66.7%	66.7%	66.7%
	Other	23	0.0%	4.3%	0.0%	30.4%	0.0%	34.8%
	Small	85	15.6%	11.8%	62.5%	56.5%	62.5%	56.5%
Power Marketer	Large	18	18.2%	22.2%	27.3%	27.8%	27.3%	27.8%
	Medium	18	14.3%	11.1%	85.7%	66.7%	85.7%	66.7%
	Other	71	14.3%	2.8%	42.9%	23.9%	42.9%	25.4%
	Small	67	10.5%	7.5%	47.4%	29.9%	47.4%	29.9%
Regional Transmission Organization/Independent System Operator	Other	7	0.0%	100.0%	0.0%	85.7%	0.0%	100.0%
Transmission	Other	7	0.0%	0.0%	0.0%	42.9%	0.0%	42.9%
Total		**3358**	**27.8%**	**15.6%**	**64.6%**	**52.0%**	**64.6%**	**52.3%**

Self-Selection Bias Assessment

As described in Appendix D, the regression-adjusted imputation used to extrapolate survey results to the survey population limited self-selection bias by using data from the mandatory EIA-861 survey, where available. A subsample was also used, as described above, for comparison with the general respondents. The subsample procedures were carried out, and follow-up efforts extended from the subsample to the overall survey frame for larger entities to maximize the overall response rate. The table above summarizes the response rates for the general respondents and the subsample for the advanced metering and demand response sections of the 2010 FERC Survey. Comparison of the response rates suggests no strong evidence of self-selection bias.