electric rate plan forecast for the megawatt reductions achieved.[289] Decoupling policies are also the subject of ongoing discussions within the Mid-Atlantic Distributed Resources Initiative (MADRI).[290]

Cost Recovery and Incentives for Enabling Technologies

Without additional technology, customer actions in response to prices, incentives, or directions from grid operators cannot be (a) measured and compensated, or (b) enabled. One study noted that without near universal installation of advanced metering, demand response activity for smaller customers will likely be limited to customers with large loads suitable for load control.[291] Wide-scale upgrading of meters or deployment of advanced metering and other enabling technologies requires substantial investments and outlays of capital. Utilities are reluctant to undertake these investments unless the business case for deployment is sufficiently positive to justify the outlay. In addition, utilities are concerned about whether meters could become a stranded asset under future deregulation – that is, is there long-term regulatory certainty to their investment?

As Chapter III noted, the business case for advanced metering can include numerous operational cost savings for distribution utilities, in addition to demand response-related savings. Operational benefits may largely cover much of the cost of the deployment, as well as accelerating its cost recovery. Utilities need to conduct a fair and reasonable cost-benefit analysis of adopting metering infrastructure that takes into account the nature and needs of the service territory.[292] Recovery of at least part of utility investment in metering, either through expensing or rate-basing, may be necessary. Without cost recovery, utilities may not have an incentive to roll out advanced metering to all customers. As was the case with utility investment in demand response, in order to provide sufficient incentive for utility investment in advanced metering, returns from this investment need to be at least commensurate with returns that utilities can get from their generation and transmission assets.

Cost recovery of advanced metering in rates has been the subject of regulatory proceedings. Because these deployments may require an increase in rates, it is uncertain whether states will allow full deployments to be fully rate-based, amortized, or expensed. UtiliPoint presented the results of an earlier survey at the FERC Technical Conference (see Figure VII-1) that suggested that most of the regulators contacted supported at least partial cost recovery of advanced metering and demand response. Rate recovery is not without controversy. For instance, consumer groups in California argued against rate recovery of advanced metering in the proceedings associated with statewide deployment.[293]

Until uncertainty about rate recovery of advanced metering can be resolved, and that meters will not become a stranded asset under future deregulation, utilities will be reluctant to invest in the technology.[294] Similarly, utilities will also need to know whether retail rate regulators will approve a

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[289] Richard Miller (Consolidated Edison), FERC Technical Conference, January 25, 2006, transcript, 64: 250.

[290] See http://www.energetics.com/MADRI/ for presentations and papers.

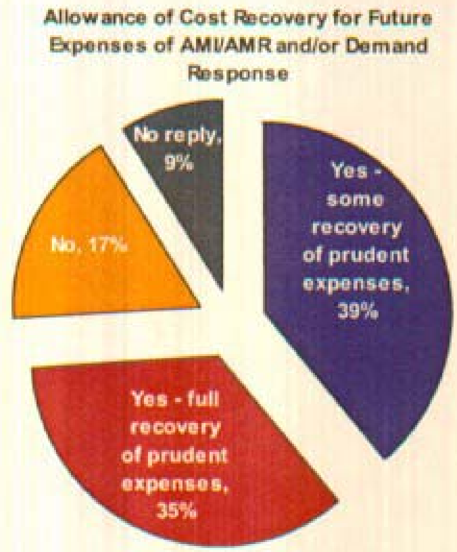
[291] UtiliPoint, *Outlook & Evaluation of Demand Response*, June 2005, 9.

[292] After the assessment period in California's Advanced Metering Initiative, the three investor-owned utilities proposed very different metering systems and infrastructure, based on the "nature" of their customers and on customer responses during the pilot period. See "California's Statewide Pricing Pilot: Overview of Key Findings," Presentation made to MADRI, May 4, 2005, 18-22.

[293] See, for example, prepared Testimony of Jeffrey A. Nahigian, in SDG&E's Application for Adoption of an Advanced Metering Infrastructure (A. 05-03-015).

[294] Colledge, Justin A., et al., "Power by the Minute." *McKinsey Quarterly*, 2002, #1: 73-80.

Figure VII-1. Regulator treatment of AMI and Demand Response



Source: Patti Harper-Slaboszewicz, UtiliPoint, "Regulator Interest in AMI and Demand Response," written remarks submitted as panelist, FERC Technical Conference, 5

concurrent retail dynamic pricing structure. Utility delay or non-action on advanced metering deployment due to these uncertainties may limit the potential for demand response in the United States.

Another cost-recovery barrier raised at the FERC Technical Conference is the disconnect between the economic life of advanced metering infrastructure and its accounting depreciation period. Southern California Edison (SCE) reports that "many utilities, including us, are concerned about the potential that AMI technology will not last as long as its depreciation period… Since the ANSI meters and communication networks will have to operate in very difficult environmental conditions over a long time, if the life of these systems falls short, this could result in significant cost impacts for our customers."[295] Aligning the economic life with the accounting life will remove this disincentive.

In addition, advances in technology and cost declines associated with metering and controls, in combination with the greater system benefits they now offer, should also help ameliorate concerns about cost-effectiveness.

Barriers to Providing Demand-Response Services by Third Parties

While the development of organized markets and independent system operators (ISOs) and Regional Transmission Organizations (RTOs) demand-response programs has created opportunities for the development of third-party demand response providers, shifting regulatory rules and potential sunset of various demand-response programs has proven to be a disincentive. Many third-parties partner with utilities, using various risk- and profit-sharing models. The providers are often invisible to retail customers whose demand response they enable. Because third parties often bear the risks of programs

[295] Paul DeMartini (Southern California Edison), FERC Technical Conference, transcript, 23: 88-89.

dependent on enabling technologies, they need long-term regulatory assurance or long-term contracts to finance the capital they need from banks.

Need for Additional Research on Cost-Effectiveness and Measurement of Reductions

As states and ISOs have implemented various price-based and incentive-based demand response programs, it has become clear that there are key deficiencies in the measurement of demand response and the means to assess cost-effectiveness. The need was articulated by Chuck Goldman of the Lawrence Berkeley National Laboratory (LBNL) at the FERC Technical Conference, "the third general area is strengthening demand-response analysis and valuation, so that program designers, policymakers, and customers can anticipate demand-response impacts and benefits. Demand-response program managers need to be able to reliably measure the net benefits of demand-response options, both costs and benefits, to ensure that they are effective at providing needed demand reductions and are cost effective to consumers."[296] Improvements in these areas will assist in state deliberations and in increasing the level of effective and beneficial demand response.

There are several problems with the current demand-response measurement methods. Evaluation of demand-response programs requires accurate measurement or estimation of the reductions effected by customers. At present, calculation of demand-response impacts is based on a combination of statistical estimation and engineering analysis, but there does not appear to be any consistency in these methods across utilities, states, and ISOs. For instance, several methods are currently used in ISO programs to estimate what customer demand would have been in lieu of customer actions to reduce consumption (i.e., the customer baseline). Some ISOs use an average usage over a set number of days, while others use the average of consumption immediately prior to and after demand-response events.

The ability to forecast and understand how greater price-responsiveness will affect load shapes, load growth, and resource needs is limited. LBNL's Chuck Goldman stated: "The impacts from price based demand response, which depend heavily on customer behavior, are really less well known. There are a number of studies that have tried to calculate the elasticity of demand, and there's been a lot of work done on it, but when you actually translate that work into the actual system impacts, hour by hour, there's a lot of work that needs to be done."[297]

There is also disagreement about what should be included in the cost-effectiveness and program evaluations. Most of the current tests for cost-effectiveness[298] were designed to assess energy efficiency and load-management activities by vertically-integrated utilities in non-restructured environments. In particular, the current tests were originally designed to establish generation equivalency for demand response, not to evaluate demand response in its entirety. Given the changes in industry structure and the existence of organized markets, these tests need to be updated. Other costs and benefits such as customer, environmental, societal, risk information, opportunity, and other difficult-to-quantify impacts are excluded. The need to update the tests is well understood, and California has taken a lead in developing an integrated efficiency and demand-response framework

[296] Charles Goldman (LBNL), FERC Technical Conference, transcript, 14: 7-15.

[297] Goldman, FERC Technical Conference, transcript, 21:18-24.

[298] The most well-known set of cost-effectiveness tests is the Standard Practice Methodology developed in California in the late 1970s and early 1980s (also known as the "California tests").

and is funding research in this area.[299] There is also no consistency in the evaluation methodologies that have been conducted by the ISOs on their programs.

The need for clarity on cost-effectiveness methods is also an issue in the assessment of advanced metering. In particular, the inclusion and valuation of a wide variety of operational benefits such as remote shut-off/turn-on, reduction in estimated bills, and demand response is subject to debate. When these features are part of the cost-benefit calculus, the payback period for an investment in advanced meters shortens considerably.[300] Utilities and regulators may also fail to include the operations and maintenance savings that accrue from demand-response programs and advanced metering but exceed narrow program costs. Research and consensus on appropriate costs and benefits to measure are needed in this area.

Existence of Specific State-Level Barriers to Greater Demand Response

In several states, the policies of retail rate regulators and state statutes create barriers to implementing greater levels of demand response and development of price-based programs. For example, California and New York laws effectively limit the ability to introduce new time-based rates, especially real-time pricing. In California, a bill was passed during the California Crisis (AB1-X) that limits the ability of the California Public Utility Commission (CPUC) to implement time-based rates such as Critical Peak Pricing (CPP) for residential customers. Bruce Kaneshiro of the CPUC reported at the FERC Technical Conference that "depending on your legal interpretation of the code of the language in that bill, you could interpret it to mean that the commission is prohibited from actually raising the rates for most of its residential customers until the power that was procured by the Department Water Resources has been effectively paid off. That won't happen until 2011."[301] In New York, state law prohibits mandatory time-of-use rates for residential customers.[302] The New York law places a cap on the level of price-responsiveness that can be implemented in the state, and limits state policy to voluntary price-based demand response in the residential sector. One commenter interpreted the recently passed HB 6 in Delaware to phase-in higher retail prices to contain similar restrictions.[303]

State policies with regard to disbursement of societal-benefit charge funds[304] can also provide a barrier to greater demand response. Commissioner Anne George of Connecticut reports that they "had some initial problems with lack of support from our energy conservation and management board and the utility in terms of how to spend the system benefit charge – the funds collected from that. I think a lot of that was centered around not understanding demand response as a permanent tool."[305]

Until these statutes and policies (and others like them in other states) are no longer enforced or are repealed, the full potential for demand response will not be achieved.

[299] PIER Demand Response Research Center, Research Opportunity Notice DRRC RON-01, *Establish the Value of Demand Response; Develop an Integrated Efficiency Demand Response Network.* July 21, 2005.

[300] Roger Levy, "Establishing the AMI Business Case Framework: Advancing Technology to Support Utility, Customer and Societal Needs," presentation to MADRI AMI subgroup, Philadelphia, PA: May 4, 2005; and David B. Smith, Citigroup, *Meter Read: Pushing the Needle to Smart Metering.* February 2006.

[301] Bruce Kaneshiro (CPUC), FERC Technical Conference, transcript, 201:7-13.

[302] See, New York State Public Service Law §66(27).

[303] Delaware HB 6, http://www.legis.state.de.us/LIS/LIS143.NSF/vwLegislation/HB+6?Opendocument.

[304] Societal benefits charges are non-bypassable charges on customer bills that are used by multiple states to fund a variety of activities, including energy efficiency, renewable energy, low-income energy assistance, and demand response.

[305] Anne George (CT DPUC), FERC Technical Conference, 236-237.

Specific Retail and Wholesale Rules that Limit Demand Response

Similar to the barriers caused by existing state statutes and policies about pricing and disbursement of funds, certain wholesale and retail market designs that have evolved over the last decade include rules and procedures that are not particularly friendly to demand participation. These problems include provisions included in state restructuring statutes, settlement and payment procedures, and frequent changes in market design and rules.

An example of provisions in state restructuring statutes that have the effect of limiting demand response is the requirement that retail electric companies in the Electric Reliability Council of Texas (ERCOT) must be associated with and settle with only one Qualifying Scheduling Entity (QSE). This requirement creates problems for companies that are interested in aggregating customer load reduction. Unless the load-reduction company limits its aggregation to the customers of one retail electric company, it needs to develop contractual agreements with multiple retail electric companies and QSEs in order to get paid for any load reduction it provides to the market. This dynamic is one of the reasons that the demand-response provider company Comverge chose not to activate the air conditioner switches that it bought from CenterPoint Energy.

Settlement issues related to payment for load reductions to third-party companies continues to be a problem in the ISO markets.[306] Standard settlement procedure in the ISOs is to complete final settlement for positions between 60 to 90 days after the close of the real-time or day-ahead market. Third-party aggregators complain that this settlement provision delays when they can provide customers payments for their actions. For example, participants in a Mid-Atlantic Distributed Resources Initiative (MADRI) meeting in December 2005 indicated that they still had not received payments for load reductions that had occurred during the previous summer. Provisions in the PJM tariff also make it difficult for third-party aggregators to provide the ISO an accounting of when curtailments occurred within a set time period. Since distribution utilities have exclusive access to meter data, third-party aggregators must wait until the utilities complete their meter reading and verification processes before they can submit the curtailment data to the ISOs. While PJM indicates that this problem has been resolved by the time of the FERC Technical Conference, a more systemic solution is needed. Deployment of advanced metering and greater real-time access to meter reads by third-party providers will assist in the resolution of this payment issue.[307]

Insufficient Market Transparency and Access to Data

Lack of access to data has been identified as a barrier to demand response. Greater transparency of unregulated retailer price offers and information on the amount of load under time-based rates or pricing will assist grid operation and planning. As Chuck Goldman of LBNL states: "If you want to move toward having customers being exposed to prices, you have to understand what's happening in the market, and, right now, we have very little information about what's happening among retailers in this area."[308]

[306] Bernie Neenan, Richard N. Boisvert and Peter A. Cappers, "What Makes a Customer Price-Responsive?" *The Electricity Journal*, 15 #3 (April 2002), 53, discussing NYISO's price-response load programs in the summer of 2001; conversations with PJM officials in the summer of 2005 reveal that this problem persists.

[307] PJM is discussing solutions to this problem in its Demand-Side Working Group: http://www.pjm.org/committees/working-groups/dsrwg/dsrwg.html.

[308] Chuck Goldman (LBNL), FERC Technical Conference, 48:20-24.

A connected but larger barrier related to data is timely access to meter data. Customer response to time-varying prices has the most impact when customers can see the result of their actions in real-time or near real-time. One of the benefits associated with advanced metering is the ability to measure and provide usage. Nevertheless, policies on access to meter data have not kept up with the developments and advancements in advanced metering technology and data retrieval. Typically, the rules and tariffs in operation for distribution utilities provide access to meter reads to customers, but with some time lag. More problematic is the access to customer meter data for independent retailers and aggregators. Ideally, in an efficient and transparent market, retailers would be able to base their price offerings and scheduling/settlement on knowledge about actual customer load shape. While there are exceptions, such as the meter data access policies in ERCOT, current utility tariffs and policies make access to this data time-consuming and expensive.

Better Coordination of Federal-State Jurisdiction Affecting Demand Response

While states have primary jurisdiction over demand response, demand response plays a role in wholesale markets under Commission jurisdiction. Some commentators such as Steel Manufacturers Association,[309] Alcoa,[310] and Heffner and Sullivan[311] have suggested that confusion over the scope of demand response in wholesale markets has limited the full potential of demand response. Greater clarity and coordination between wholesale and state programs is needed.

Recommendations

Demand response deserves serious attention. Staff recommends that the Commission: (1) explore how to better accommodate demand response in wholesale markets; (2) explore how to coordinate with utilities, state commissions and other interested parties on demand response in wholesale and retail markets; and (3) consider specific proposals for compatible regulatory approaches, including how to eliminate regulatory barriers to improved participation in demand response, peak reduction and critical peak pricing programs. Staff also encourages states to continue to consider ways to actively encourage demand response at the retail level. In particular, staff recommends that the Commission and states work cooperatively in finding demand response solutions.

[309] Steel Manufacturers Association, comments filed in Docket AD06-2, December 19, 2005.

[310] Alcoa, comments filed in Docket AD06-2, December 19, 2005.

[311] Grayson Heffner and Freeman Sullivan, *A Critical Examination of ISO-Sponsored Demand Response Programs*, August 2005.

Appendices

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Appendix A: EPAct 2005 Language on Demand Response and Smart Metering

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 nonregulated 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: Acronyms Used in the Report

Acronym		Term (see glossary for definition)
ACEEE		American Council for an Energy Efficient Environment
AEP		American Electric Power
AMI		Advanced Metering Infrastructure
AMR		Automated Meter Reading OR Automatic Meter Reading
AMRA		Automatic Meter Reading Association
ANSI		American National Standards Institute
APPA		American Public Power Association
APR		Actual peak reduction
APS		Arizona Public Service
A/S		Ancillary services
BPA		Bonneville Power Administration
BPL		Broadband over power-line
C&I		Commercial and industrial customers
CAEM		Center for the Advancement of Energy Markets
CAISO		California Independent System Operator
CAP		Capacity market programs
CBL		Customer baseline level
CEC		California Energy Commission
CERA		Cambridge Energy Research Associates
CCPG		Colorado Coordinated Planning Group
CERTS		Consortium for Electric Reliability Technology Solutions
CPA		California Power Authority
CPP		Critical peak pricing
CPP-F		Critical peak-fixed
CPP-V		Critical peak-variable
CPUC		California Public Utilities Commission
CRA		Charles River Associates (now renamed CRA)
CSEM		Center for the Study of Energy Markets
CSP		Curtailment service provider
CT		Combustion turbine
DADRP		Day-Ahead Demand Response Program
DA-RTP		Day-ahead real-time pricing
DEFG		Distributed Energy Financial Group
DG		Distributed generation
DLC		Direct load control
DOE		Department of Energy (U.S.)
DR		Demand response
DRR		Demand response resources
DRCC		Demand Response Coordinating Council (coalition)
DRRC		Demand Response Research Center (California)
DRAM		Demand Response and Advanced Metering Coalition
DSM		Demand-side management
ECAR	*	East Central Area Reliability Coordination Agreement
EdF		Electricité de France
EDRP		Emergency demand response program
EE		Energy efficiency

EEI		**Edison Electric Institute**
EIA		**Energy Information Administration (U.S.)**
EPA		**Environmental Protection Agency (U.S.)**
EPAct 2005		**Energy Policy Act of 2005**
EPRI		**Electric Power Research Institute**
ERCOT	* **	**Electric Reliability Council of Texas, Inc.**
FERC		**Federal Energy Regulatory Commission (U.S.)**
FRCC	* **	**Florida Reliability Coordinating Council**
GAO		**General Accountability Office (U.S.)**
GMP		**Green Mountain Power**
HVAC		**Heating, ventilation, and air conditioning**
kW		**Kilowatt-hour**
kWh		**Kilowatt-hour (one thousand watt-hours)**
I/C		**Interruptible /Curtailable**
ICAP		**Installed capacity**
ICAP-SCR		**Installed capacity special case resources (NYISO category)**
ICF		**ICF International – consulting firm**
IEA		**International Energy Agency (Paris)**
IOU		**Investor-owned utility**
ISO		**Independent system operator**
ISO-NE		**Independent System Operator of New England**
LaaR		**Load acting as a resource (ERCOT category)**
LBNL		**Lawrence Berkeley National Laboratory**
LIPA		**Long Island Power Authority**
LMP		**Locational marginal price/pricing**
LSE		**Load-serving entity**
MAAC	*	**Mid-Atlantic Area Council (geographically within PJM)**
MADRI		**Mid-Atlantic Distributed Resources Initiative**
MAIN	*	**Mid-America Interconnected Network**
MDM		**Meter data management**
MISO		**Midwest Independent System Operator**
MRO	**	**Midwest Reliability Organization**
MTEP		**Midwest ISO Transmission Expansion Plan 2005**
MW		**Megawatt (one million watts)**
MWh		**Megawatt-hour (one million watt-hours)**
NARUC		**National Association of Regulatory Utility Commissioners**
NEDRI		**New England Distributed Resources Initiative**
NERA		**NERA Economic Consulting**
NERC		**North American Electric Reliability Council**
NPCC	**	**Northeast Power Coordinating Council**
NRECA		**National Association of Rural Electric Cooperatives**
NTAC		**Northwest Transmission Assessment Committee**
NYDER		**New York Department of Environmental Resources**
NYISO		**New York Independent System Operator**
NYPSC		**New York Public Service Commission**
NYSERDA		**New York State Energy Research and Development Authority**
O&M		**Operations and maintenance**
ORNL		**Oak Ridge National Laboratory (U.S.)**
PCT		**Programmable communicating thermostat**
PDCI		**Pacific Direct Current Inter-tie**

PG&E		**Pacific Gas & Electric**
PIER		**Public Interest Energy Research (CEC)**
PJM		**PJM Interconnection, L.L.C**
PLC		**Power line communication**
PNNL		**Pacific Northwest National Laboratory (DOE)**
POLR		**Provider of last resort**
PLMA		**Peak Load Management Association**
PPR		**Potential peak reduction**
PSC		**Public Service Commission**
PSE		**Puget Sound Energy**
PUC		**Public Utility Commission**
PURPA		**Public Utility Regulatory Policies Act of 1978**
QSE		**Qualifying scheduling entity**
RAP		**Regulatory Assistance Project**
RF		**Radio frequency**
RFC	**	**Reliability*First* Corporation**
RFP		**Request for proposals**
RMATS		**Rocky Mountain Area Transmission Study**
RRO		**Regional reliability organization**
RTEP		**Regional transmission expansion plan**
RTO		**Regional transmission organization**
RTP		**Real-time pricing**
SCADA		**Supervisory control and data acquisition**
SCE		**Southern California Edison**
SCR		**Special Case Resources (NYISO category)**
SDG&E		**San Diego Gas & Electric**
SERC	**	**SERC Reliability Corporation**
SERC	*	**Southeastern Electric Reliability Council**
SPP	* **	**Southwest Power Pool, Inc.**
SPP		**Statewide Pricing Pilot (California)**
SRP		**Salt River Agricultural Improvement & Power District**
SSG-WI PWG		**Seams Steering Group – Western Interconnection Planning Work Group**
STEP		**Southwest Transmission Expansion Plan group**
SWAT		**Southwest Area Transmission**
TBL		**Transmission business line**
TWACS		**Two-way automatic communication system**
TO		**Transmission owner**
TOU		**Time-of-use (rate)**
UFLS		**Under frequency load shedding**
UVLS		**Under voltage load shedding**
VPP		**Variable peak pricing**
WECC	* **	**Western Electricity Coordinating Council**

* former NERC region used in FERC Surveys and in Chapter VI

** proposed new Regional Reliability Organizations

Appendix C: Glossary for the Report

Actual Annual MWh change: The actual sum of MWh changes due to customer participation in a sponsored Demand Response (DR) program.

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

Actual Peak Reduction (APR): The coincident reductions to the annual peak load (measured in megawatts) achieved by customers that participate in a demand response program at the time of the annual system peak of the utility or ISO. It reflects the changes in the demand for electricity resulting from a sponsored demand response program that is in effect at the same time a utility or ISO experiences its annual system peak load, as opposed to the installed peak load reduction capability (i.e., Potential Peak Reduction). It should account for the regular cycling of energy efficient units during the period of annual system peak load. For curtailment service providers (CSP), the actual peak reduction should include the demand response load provided at the time of the peak for the region in which they aggregate customer load. For utilities, it should include the demand response load at the time of the utility annual system peak load. For ISOs/RTOs, it should include the demand response load at the time of the ISO/RTO annual system peak load.

Advanced Metering Infrastructure (AMI): AMI is defined as the communications hardware and software and associated system and data management software that creates a network between advanced meters and utility business systems and which allows collection and distribution of information to customers and other parties such as competitive retail providers, in addition to providing it to the utility itself.

American Council for an Energy-Efficient Economy (ACEEE) is a nonprofit organization whose research reports examine energy efficiency as a means of promoting both economic prosperity and environmental protection.

Ancillary Services: Those services necessary to support the transmission of electric power from seller to purchaser, given the obligations of control areas and transmitting utilities within those control areas, to maintain reliable operations of the interconnected transmission system. Ancillary services supplied with generation include load following, reactive power-voltage regulation, system protective services, loss compensation service, system control, load dispatch services, and energy imbalance services.

Ancillary Service Market Programs: Demand response programs in which customers bid load curtailments in ISO/RTO markets as operating reserves. If their bids are accepted, they are paid the market price for committing to be on standby. If their load curtailments are needed, they are called by the ISO/RTO, and may be paid the spot market energy price.

Asset Management: The ability to leverage the value of metering data and other available information to increase the value of utility investments and/or to improve customer service. One example is using hourly interval data to measure the load on transformers at the time of the system peak.

Automated Meter Reading: automatic or automated meter reading -- allows meter read to be collected without actually viewing or touching the meter with any other equipment. One of the most prevalent examples of AMR is mobile radio frequency whereby the meter reader drives by the property, and equipment in the car receives a signal sent from a communication device under the glass of the meter.

Bid Limits: The maximum $/MWh bid that can be submitted by a program participant.

Billing or Revenue Meter: Meters installed at customer locations that meter electric usage and possibly other parameters associated with a customer account and provide information necessary for generating a bill to the customer for the customer account.

Bonneville Power Administration (BPA): A federal power marketing and electric transmission agency headquartered in Portland, Oregon.

Capable: AMI network could initiate interval data and collection without a physical visit to the meter site to reprogram it or to add an extra device of some kind.

Capacity Market Programs (CAP): Demand response programs in which customers offer load curtailments as system capacity to replace conventional generation or delivery resources. Customers typically receive day-of notice of events and face penalties for failure to curtail when called upon to do so. Incentives usually consist of up-front reservation payments.

Commercial sector: An energy-consuming sector that consists of service-providing facilities and equipment belonging to: businesses; federal, state, and local governments; and other private and public organizations, such as religious, social, or fraternal groups. The commercial sector includes institutional living quarters, sewage treatment facilities, and street lighting. Common uses of energy associated with this sector include space heating, water heating, air conditioning, lighting, refrigeration, cooking, and running a wide variety of other equipment. Note: This sector includes generators that produce electricity and/or useful thermal output primarily to support the activities of the above-mentioned commercial establishments.

Cooperative Electric Utility: An electric utility legally established to be owned by and operated for the benefit of those using its service. The utility company will generate, transmit, and/or distribute supplies of electric energy to a specified area not being serviced by another utility. Such ventures are generally exempt from federal income tax laws. Most electric cooperatives were initially financed by the Rural Utilities Service (formerly the Rural Electrification Administration), U.S. Department of Agriculture.

Critical Peak Pricing (CPP): CPP rates are a hybrid of the TOU and RTP design. The basic rate structure is TOU. However, provision is made for replacing the normal peak price with a much higher CPP event price under specified trigger conditions (e.g., when system reliability is compromised or supply prices are very high).

Curtailment Service Provider (CSP): Demand response load providers that are not necessarily load serving entities. CSPs may sponsor demand response programs and sell the demand response load to utilities, RTOs and/or ISOs.

Customer Account: A record at the energy provider that identifies an entity receiving electric service at one or more locations within the utility service footprint. The identified entity is responsible for paying the cost of energy consumed and metered at the location(s) on the account. There may be no meter associated with the customer account (such as with street lights), or one or more meters associated with a particular customer account.

Demand: Represents the requirements of a customer or area at a particular moment in time. Typically calculated as the average requirement over a period of several minutes to an hour, and thus usually expressed in kilowatts or megawatts rather than kilowatt-hours or megawatt-hours. Demand and load are used interchangeably when referring to energy requirements for a given customer or area.

Demand Bidding/Buyback (DB): A demand response program where customers or curtailment service providers offer bids to curtail based on wholesale electricity market prices or an equivalent. Mainly offered to large customers (e.g., one MW and over), but small customer demand response load can be aggregated by curtailment service providers and bid into the demand bidding program sponsor.

Demand Response (DR): The planning, implementation, and monitoring of activities designed to encourage customers to modify patterns of electricity usage, including the timing and level of electricity demand. Demand response covers the complete range of load-shape objectives and customer objectives, including strategic conservation, time-based rates, peak load reduction, as well as customer management of energy bills.

Demand Response Event: A period of time identified by the demand response program sponsor when it is seeking reduced energy consumption and/or load from customers participating in the program. Depending on the type of program and event (economic or emergency), customers are expected to respond or decide whether to respond to the call for reduced load and energy usage. The program sponsor generally will notify the customer of the demand response event before the event begins, and when the event ends. Generally each event is a certain number of hours, and the program sponsors are limited to a maximum number of events per year.

Demand Response Load: The load reduction that results from demand response activities.

Direct Load Control (DLC): A demand response activity by which the program operator 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.

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

EIA ID Number: Unique identification number assigned by EIA to companies and entities operating in the electric power industry.

Economic Demand Response Event: A demand response 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 of the program sponsor orthe RTO/ISO.

Edison Electric Institute (EEI): The trade association for the investor-owned utility companies.

Elasticity of Demand: The degree to which consumer demand for a product responds to changes in price, availability or other factors.

Electric Power: The rate at which electric energy is transferred. Electric power is measured by capacity and is commonly expressed in megawatts (MW).

Electric Power Research Institute (EPRI): An independent, non-profit energy and environmental research organization which brings together members, participants, and the Institute's scientists and engineers to work collaboratively on solutions to electric power issues.

Electric Reliability Council of Texas (ERCOT): The electric reliability organization which ensures reliable and cost-effective operation of the grid in the Texas area.

Electric Utility: A corporation, person, agency, authority, or other legal entity or instrumentality aligned with distribution facilities for delivery of electric energy for use primarily by the public. Included are 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 that own distribution facilities are also included.

Electricity: A form of energy characterized by the presence and motion of elementary charged particles generated by friction, induction, or chemical change.

Emergency Demand Response Event: A demand response event called by the program sponsor in response to an emergency of the delivery system of the demand response sponsor or of another entity such as a utility or ISO.

Emergency Demand Response Program (EDRP): A demand response program that provides incentive payments to customers for load reductions during periods when reserve shortfalls arise.

Energy: The capacity for doing work as measured by the capability of doing work (potential energy) or the conversion of this capability to motion (kinetic energy). Energy has several forms, some of which are easily convertible and can be changed to another form useful for work. Most of the world's convertible energy comes from fossil fuels that are burned to produce heat that is then used as a transfer medium to mechanical or other means in order to accomplish tasks. Electrical energy is usually measured in kilowatt-hours.

Energy Efficiency (EE): Refers to programs that are aimed at reducing the energy used by specific end-use devices and systems, typically without affecting the services provided. These programs reduce overall electricity consumption (reported in megawatt-hours), often, but not always, without explicit consideration for the timing of program-induced savings. Such savings are generally achieved by substituting technologically more advanced equipment to produce the same level of end-use services (e.g. lighting, heating, motor drive) with less electricity. Examples include energy saving appliances and lighting programs, high-efficiency heating, ventilating and air conditioning (HVAC) systems or control modifications, efficient building design, advanced electric motor drives, and heat recovery systems.

Enhanced Customer Service: The ability to offer ultimate customers the choice of bill data, additional rate options such as real time pricing or critical peak pricing, verify an outage or restoration of service following an outage, more information to understand a customer concern over an electric bill, reduce bill estimates when a meter read is not available, opening or closing of an account due to customer relocation without requiring a site visit to the meter(s), and/or more accurate bills.

Executive Dashboard: The ability of the AMI network to provide information that would support utility management viewing on a timely basis. The information might include current outages and MW sales. In this context, the utility would need to also have an executive dashboard application. Timely would not necessarily mean in real-time but it would likely mean that within an hour to 24 hours, management would be able to view usage measured at revenue and billing meters across the utility service territory.

Florida Reliability Coordinating Council (FRCC): The FRCC is one of eight Regional Reliability Councils in the lower 48 states that comprise the North American Electric Reliability Council (NERC). It covers Peninsular Florida, east of the Apalachicola River.

Gas Meter: A meter that measures natural gas usage for ultimate customers.

ICAP Credit: An ISO capacity credit to satisfy a resource requirement.

Independent system operator (ISO): An organization that has been granted the authority to operate, in a nondiscriminatory manner, the transmission assets of the participating transmission owners in a fixed geographic area. ISOs often run organized markets for spot electricity.

Industrial: The energy-consuming sector that consists of all manufacturing facilities and equipment used for producing, processing, or assembling goods. The industrial sector encompasses the following types of activity: manufacturing; agriculture, forestry, and fisheries; mining; and construction. Overall energy use in this sector is largely for process heat and cooling and powering machinery, with lesser amounts used for facility heating, air conditioning, and lighting. Fossil fuels are also used as raw material inputs to manufactured products. This sector may include energy deliveries to large commercial customers, and may exclude deliveries to small industrial customers which may be included in the commercial sector. It also may classify by using the North American Industry Classification System or on the basis of energy demand or annual usage exceeding some specified limit set by the energy provider.

Industrial Customer: Electric power consumers which usually consume large amounts of electricity and are usually in the manufacturing, construction, mining, agriculture, fishing or forestry industries. Utilities usually classify service to these consumers based on their power demand or an annual usage amount which exceeds some specified limit.

Interface with Water or Gas Meters: The ability of the AMI network to collect water or gas meter readings and to transmit the gas or water meter readings over the AMI network to an entity that can provide the gas or water meter readings to the gas or water utility providing the service.

Interruptible/Curtailable Service (I/C): Curtailment options integrated into retail tariffs that provide a rate discount or bill credit for agreeing to reduce load during system contingencies. Penalties may be assessed for failure to curtail. In some instances, the demand reduction may be affected by direct action of the System Operator (remote tripping) after notice to the customer in accordance with contractual provisions. For example, demands that can be interrupted to fulfill planning or operating reserve requirements normally should be reported as Interruptible Demand. Interruptible programs have traditionally been offered only to the largest industrial (or commercial) customers. Interruptible Demand as reported here does not include Direct Control Load or price responsive demand response.

Investor-Owned Utility (IOU): A utility organized under state law as a publicly traded corporation for the purposes of providing electric power service and earning profits for its stockholders.

Kilowatt (kW): One thousand watts.

Kilowatthour (kWh): One thousand watt-hours.

Line Loss: Electric energy lost because of the transmission of electricity. Much of the loss is thermal in nature.

Load (Electric): The amount of electric power delivered or required at any specific point or points on a system. The requirement originates at the energy-consuming equipment of the consumers.

Load Acting as a Resource (LaaR): An interruptible program operated by ERCOT in which customers may qualify to provide operating reserves.

Load Forecasting: The estimation of future load requirements for specified intervals for a period of time. The load forecast may provide an estimate of hourly loads for a group of ultimate customers for the next five years, for example.

Load-serving entity (LSE): Any entity, including a load aggregator or power marketer, that serves end-users within a control area and has been granted the authority or has an obligation pursuant to state or local law, regulation, or franchise to sell electric energy to end-users located within the control area.

Maximum Demand: This is determined by the interval in which the 60-minute integrated demand is the greatest.

Maximum Hourly Load: The highest amount of demand that is measured or expected to be curtailed at a certain point in time.

Megawatt (MW): One million watts of electricity.

Megawatthour (MWh): One thousand kilowatt-hours or 1 million watt-hours.

Midwest Reliability Organization (MRO): The Midwest Reliability Organization (MRO) is one of eight Regional Reliability Councils in the lower 48 that comprise NERC. Its members include the following states: Minnesota, Wisconsin, Iowa, North Dakota, South Dakota, Nebraska, Montana, Illinois and Upper Peninsula of Michigan.

Minimum Term: The minimum length in years that customers are obligated to participate in a demand response program.

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

National Association of Regulatory Utility Commissioners (NARUC): A non-profit organization whose members include the governmental agencies that are engaged in the regulation of utilities and carriers in the fifty states, the District of Columbia, Puerto Rico.

North American Electric Reliability Council (NERC): The organization certified by the Commission as the reliability organization for the nation's bulk power grid. NERC consists of eight Regional Reliability Councils in the lower 48 states. The members of these Councils are from all segments of the electricity supply industry - investor-owned, federal, rural electric cooperative, state/municipal, and provincial utilities, independent power producers, and power marketers.

Operating Company: The name a utility uses in doing business within a particular state associated with a particular service territory.

Outage Management: The response of an electric utility to an outage affecting the ultimate customers of the electric service. The utility may use the AMI network to detect outages, verify outages, map the extent of an outage, or verify the service has been restored after repairs have been made.

Peak Demand: The maximum load during a specified period of time.

Potential MWh Change: The potential total annual change in energy consumption (measured in MWh) that would result from the deployment of demand response programs. It reflects the total change in consumption if the full demand reduction capability of the program were deployed, as opposed to actual MWh change during the year.

Potential Peak Reduction: The potential annual coincident peak load reduction (measured in megawatts) that can be deployed from demand response programs. It represents the load that can be reduced either by the direct control of the utility system operator or by the consumer in response to a utility request to curtail load. It reflects the installed load reduction capability, as opposed to the Actual Peak Reduction achieved by participants, during the time of annual system peak load. It should account for the regular cycling of energy efficient units during the period of system peak load. For utilities, it should be the potential sum of demand reduction capability to their annual peak load (measured in megawatts) achieved by the program participants. For an ISO or RTO, it should be the sum of coincident reduction capability to the ISO or RTO achieved by participants at the time of system peak of the ISO or RTO. Similarly, for CSPs, it should be the sum of coincident reduction capability sponsored by the CSP and achieved by demand response program participants at the time of the peak for the region in which the CSP is aggregating customer load.

Power Marketers: Business entities, including energy service providers, that are engaged in buying and selling electricity, but do not own generating or transmission facilities. Power marketers and energy service providers, as opposed to brokers, take ownership of the electricity and are involved in interstate trade. Power marketers file with the Federal Energy Regulatory Commission (FERC) for status as a power marketer. Energy service providers may not register with FERC but may register with the states if they undertake only retail transactions.

Power Quality Monitoring: The ability of the AMI network to discern, record, and transmit to the utility instances where the voltage and/or frequency were not in ranges acceptable for reliability.

Premise Device/Load Control Interface or Capability: The ability of the AMI network to communicate directly with a device located on the premises of the ultimate customer, which may or may not be owned by the utility. These might include a programmable communicating thermostat or a load control switch.

Pre-Pay Metering: A metering and/or software and payment system that allows the ultimate customer to pay for electric service in advance.

Price Responsive Demand Response: All demand response programs that include the use of time-based rates to encourage retail customers to reduce demands when prices are relatively high. These demand response programs may also include the use of automated responses. Customers may or may not have the option of overriding the automatic response to the high prices.

Pricing Event Notification Capability: The ability of the AMI network to convey to utility customers participating in a price responsive demand response program that a demand response event is planned, beginning, ongoing, and/or ending.

Provision of Usage Information to Customers: The ability of the AMI network to convey to ultimate customers information on their usage in a timely fashion. Timely in this context would be dependent on the customer class, with larger customers generally receiving the information with less lag time than residential customers.

Public Utility: An enterprise providing essential public services, such as electric, gas, telephone, water, and sewer under legally established monopoly conditions.

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

Publicly Owned Electric Utility: A class of ownership found in the electric power industry. This group includes those utilities operated by municipalities, political subdivisions, and state and federal power agencies (such as BPA or TVA).

Railroad and Railway Electric Service: Electricity supplied to railroads and interurban and street railways, for general railroad use, including the propulsion of cars or locomotives. Such electricity is supplied under separate and distinct rate schedules.

Real Time Pricing (RTP): A retail rate in which the price for electricity typically fluctuates hourly reflecting changes in the wholesale price of electricity. RTP prices are typically known to customers on a day-ahead or hour-ahead basis.

Reduce Line Losses: The ability to use the AMI network to lower the line losses on the transmission system.

Regional transmission organization (RTO): An organization with a role similar to that of an independent system operator but covering a larger geographical scale and involving both the operation and planning of a transmission system. RTOs often run organized markets for spot electricity.

Remotely Change Metering Parameters: The ability to change parameters associated with a particular revenue or billing meter, such as the length of the data interval measured, without a site visit to the meter location.

Remote Connect/Disconnect: The ability to physically turn on or turn off power to a particular billing or revenue meter without a site visit to the meter location.

Residential: The energy-consuming sector that consists of living quarters for 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 appliances. The residential sector excludes institutional living quarters. This sector may exclude deliveries or sales to apartment buildings or homes on military bases (these buildings or homes may be included in the commercial sector).

Response Time: The maximum notice and lead time that a demand response program sponsor provides to demand response program participants prior to an economic or emergency demand response event.

Retail: Sales covering electrical energy supplied for residential, commercial, and industrial end-use purposes. Other small classes, such as agriculture and street lighting, also are included in this category.

Revenue Assurance: A set of activities designed to increase the revenue from providing electric service to ultimate customers, including locating meters without associated customer accounts, relatively high line losses compared with other similar locations, energy theft, and/or improper metering installations.

Service Territory: The area within a particular state where an electric utility is allowed to provide ultimate customers for distribution, transmission, or energy services.

Specific Event Limits: The maximum number of events that can be called during a year.

Southwest Power Pool (SPP): The Southwest Power Pool is both the RTO and NERC reliability organization for Kansas, Missouri, Oklahoma, and part of New Mexico.

System (Electric): Physically connected generation, transmission, and distribution facilities operated as an integrated unit under one centralized manager or operations supervisor.

Theft Detection: The ability to detect when a revenue or billing meter has been potentially tampered with and to indicate a potential energy theft in progress that should be further investigated by the utility.

Time-Based Rate (TBR): A retail rate in which customers are charged different prices for different times during the day. Examples are time-of-use (TOU) rates, real time pricing (RTP), hourly pricing, and critical peak pricing (CPP).

Time-of-use (TOU) Rate: A rate with different unit prices for usage during different blocks of time, usually defined for a 24 hour day. TOU rates reflect the average cost of generating and delivering power during those time periods. Daily pricing blocks might include an on-peak, partial-peak, and off-peak price for non-holiday weekdays, with the on-peak price as the highest price, and the off-peak price as the lowest price.

Transformer: A device that operates on magnetic principles to increase (step up) or decrease (step down) voltage.

Transmission: The movement or transfer of electric energy over an interconnected group of lines and associated equipment between points of supply and points at which it is transformed for delivery to consumers or is delivered to other electric systems. Transmission is considered to end when the energy is transformed for distribution to the consumer.

Transmission System (Electric): An interconnected group of electric transmission lines and associated equipment for moving or transferring electric energy in bulk between points of supply and points at which it is transformed for delivery over the distribution system lines to consumers.

Transportation: An energy consuming sector that consists of electricity supplied and services rendered to railroads and interurban and street railways, for general railroad use including the propulsion of cars or locomotives, where the electricity is supplied under separate and distinct rate schedules.

Type of Organization: in fielding the FERC Survey, this allowed Commission staff to identify the type of organization that best represents the energy market participant. The possible categories were : Investor-owned utilities (IOU), Municipal Utility (M), Cooperative Utility (C), State-owned Utility (S), Federally-owned Utility (F), Independent System Operator (ISO), Regional Transmission Operator (RTO), Curtailment Service Provider (CSP), or other (O).

Ultimate Consumer: A consumer that purchases electricity for its own use and not for resale.

Uncommitted Capacity: Generating resources that are physically located in the region, but are not dedicated or contractually committed to serve load in the region.

Water meter: A meter that measures water usage for end-use customers.

Watt (W): The unit of electrical power equal to one ampere under a pressure of one volt. A watt is equal to 1/746 horsepower.

Watt-hour (Wh): The electrical energy unit of measure equal to one watt of power supplied to, or taken from, an electric circuit steadily for one hour.

Year of Study: Identification of the projected years covered by a specified study.

Appendix D: Demand Response and Advanced Metering Source List and Bibliography

Note: where reports are publicly available on the internet, we have provided a link to the source.

Demand Response and Competition: Federal and State Reports, Orders, Conferences:

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Online Resources for further information on Demand Response and Advanced Metering:

Associations / Collections of Studies:

Association of Energy Services Professionals http://www.aesp.org/i4a/pages/index.cfm?pageid=1
American Council for an Energy-Efficient Economy - http://www.aceee.org/
Demand Response and Advanced Metering Coalition (DRAM): http://www.dramcoalition.org
Lawrence Berkeley National Laboratories, Demand Response Research Center (LBNL): http://drrc.lbl.gov/drrc.html
Midwest Energy Efficiency Alliance: http://www.mwalliance.org/
Regulatory Assistance Project (RAP). Reports and Issues newsletters on Energy Efficiency, Demand-Side Resources, and Demand Management: www.raponline.org (All RAP reports cited in this bibliography can be found at this site.)
University of California Energy Institute (UCEI), Energy Market (CSEM) Working Papers: http://www.ucei.berkeley.edu/

Regional Demand Response Programs, Initiatives, Planning:

Bonneville Power Authority (BPA):
- BPA website on demand response, transmission planning: ("about" section):

California:
- PIER Demand Response Research Center. Created by CEC in 2004 to plan and conduct multi-disciplinary research to advance DR in California.. http://drrc.lbl.gov/drrc.html
- CAISO, Demand Response: http://www.caiso.com/clientserv/load/

ERCOT: http://www.puc.state.tx.us/electric/projects/26055/26055.cfm
Mid-Atlantic Distributed Resources Initiative (MADRI)
- Meeting agendas, presentations, and reports: http://www.energetics.com/MADRI/
- Advanced Metering Tool-box: http://www.energetics.com/madri/toolbox/

New England:
- ISO-NE Demand Response
  - Working Group meeting agendas and materials at http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/dr_wkgrp/index.html
  - Demand Response main page: http://www.iso-ne.com/genrtion_resrcs/dr/index.html
- New England Distributed Resource Initiative (NEDRI)
  - Studies on the Regulatory Assistance Project (RAP) website
  - Studies prepared by state by Raab Associates

New York:
- NYISO, Demand Response: http://www.nyiso.com/public/products/demand_response/index.jsp

Pacific Northwest National Laboratory (DOE):
- Energy Efficiency and Renewable Energy Research: http://eere.pnl.gov/program_areas.stm

PJM Interconnection, LLC:
- Demand Response Working Group: http://www.pjm.org/committees/working-groups/dsrwg/dsrwg.html
- Demand Response: http://www.pjm.org/services/demand-response/demand-response.html

Appendix E: The Public Process Leading to the Report

On November 3, 2005, Commission staff issued a notice of proposed voluntary survey and technical conference regarding Assessment of demand response resources, asking g for comments on a proposed survey, technical conference topics, and interest regarding participating at the conference.[1] The November 2005 Notice set a comment date of December 5, 2005 for entities that wanted to comment on proposed survey questions and/or request to participate in the technical conference. A number of entities provided comments:

- Alcoa Inc.
- American Electric Power Service Corporation
- American Public Power Association
- Avista Corporation
- California Department of Water Resources State Water Project
- Demand Response and Advanced Metering Coalition
- Detroit Edison Company
- Edison Electric Institute
- Exelon Corporation
- FirstEnergy Service Company
- Stephen George of Charles River Association
- Hunt Technologies Inc.
- ISO New England
- Mid-Atlantic Distributed Resources Initiative (MADRI)
- Midwest Independent Transmission System Operator, Inc.
- National Grid USA
- New England Conference of Public Utilities Commissioners
- New York State Electric and Gas Corporation
- PJM Interconnection, L.L.C.
- PNM Resources Inc.
- Portland General Electric Company
- San Diego Gas & Electric Company
- Salt River Project Agricultural Improvement & Power District
- Silver Spring Networks
- Southern California Edison Company
- Southern Company Services, Inc.
- Steel Manufacturers Association
- U.S. Environmental Protection Agency
- Xcel Energy

The November 2005 Notice established a comment date of December 19, 2005 for entities that wanted to comment on proposed technical conference topics. A number of entities provided comments:

- Alcoa Inc.

[1] This notice was published in the Federal Register on November 9, 2005, 70 Fed. Reg. 68,002 (2005) (November 2005 Notice).

- American Public Power Association
- California Public Utility Commission staff / California Energy Commission
- Central Maine Power Corporation, New York State Electric and Gas Corporation, and Rochester Gas and Electric Company
- Cinergy Services, Inc.
- Consumers Energy Council of America
- Demand Response and Advanced Metering Coalition
- Distributed Energy Financial Group, LLC
- Edison Electric Institute
- Exelon Corporation
- Idaho Power Company
- ISO New England
- Midwest Independent Transmission System Operator, Inc.
- National Grid USA
- Hunt Technologies Inc.
- MADRI
- MidAmerican Energy Company
- Missouri Public Service Commission
- National Energy Marketers Association
- Nevada Power Company / Sierra Pacific Power Company
- New England Conference of Public Utilities Commissioners
- New York Independent System Operator, Inc.
- New York State Public Service Commission
- Pacific Gas and Electric Company
- Pennsylvania Public Utility Commission
- PJM Interconnection, L.L.C.
- Portland General Electric Company
- Public Service Commission of Maryland
- Public Utilities Commission of Ohio
- San Diego Gas & Electric Company
- Silicon Valley Leadership Group
- Southern California Edison Company
- Southern Company Services, Inc.
- Steel Manufacturers Association

Commission staff issued notices of the January 25, 2006 technical conference.[2] The following entities submitted comments / testimony:

- Jeffrey Bladen, PJM Interconnection, L.L.C. – presentation
- James Brew, Steel Manufacturers Association – presentation
- Ken Corum, Northwestern Power and Conservation Council – presentation
- Jeff Davis, Missouri Public Service Commission – presentation
- Paul Demartin, Southern California Edison Company – presentation

[2] Notice of the technical conference was published in the Federal Register on December 16, 2005, 70 Fed. Reg. 74,804 (2005). Subsequent notices to the technical conference were published in the Federal Register. *See* 71 Fed. Reg. 3,287 (2006); *see also* 71 Fed. Reg. 4,361 (2006).

- Charles Goldman, Lawrence Berkeley National Laboratory – presentation
- Phil Giudice, EnerNOC – presentation
- Patti Harper-Slaboszewicz, Utilitpoint International – presentation
- Bruce Kaneshiro, California Public Utilities Commission – presentation
- John M. Kelly, American Public Power Association – presentation
- Tom Kerr, U.S. Environmental Protection Agency – presentation
- David Lawrence, New York Independent System Operator, Inc. – presentation
- Ronald McNamara, Midwest Independent System Operator, Inc. – presentation
- David Meade, Praxair, Inc. – presentation
- Jay Morrison, National Rural Electric Cooperative Association – presentation
- Tim Roughan, National Grid – presentation
- Peter Scarpelli, RETX – presentation
- Doug Stinner, PPL Electric Utilities – presentation
- Rick Tempchin, Edison Electric Institute – presentation
- Alan Wilcox, Sacramento Municipal Utility District – presentation
- Henry Yoshimura, ISO New England – presentation
- Xcel Energy Comments

On March 15, 2006, Commission staff issued a notice of issuance of voluntary survey of advanced metering and demand response programs regarding assessment of demand response resources.[3]

[3] Notice of the survey was published in the Federal Register on March 24, 2006, 71 Fed. Reg. 14,888 (2006).

Appendix F: The FERC Survey

Summary

The Energy Policy Act of 2005 (EPAct 2005) required that the Federal Energy Regulatory Commission (FERC) provide Congress with both qualitative information[4] about demand response (DR) and advanced metering infrastructure (AMI) as well as specific quantitative, region-specific information. Commission staff determined that a survey of all private and public entities that provide electric power and DR to customers would help fulfill the requirement.

Between September 2005 and June 2006, Commission staff—with the technical support of UtiliPoint International, Inc. (UtiliPoint):

- developed a survey and sampling design;
- issued a proposed survey for public comment as well as a notice announcing a related technical conference in the November 9, 2005 *Federal Register*;
- gathered public information and guidance for the FERC Survey through the January 2006 technical conference;
- initiated and successfully completed the Office of Management and Budget's (OMB) authorization process for federal information collections;
- fielded the FERC Survey, collected the data and completed a substantial amount of data analyses for this report.

The response rate for the FERC Survey was 56% for the demand response section (1,886 of the 3,365 entities who received the FERC Survey) and 55% for the AMI section (1,860 of the 3,365 entities who received the FERC Survey).

The FERC Survey response rate resulted from its being voluntary (instead of mandatory, like the EIA-861) and asking for more information on demand-side resources than the EIA Form-861survey.

The following provides a detailed review of the steps Commission staff took to achieve this critical response rate documents the surveying process and addresses the OMB requirements for a summary of response rates and sampling results. An additional OMB requirement was to incorporate into its methodology a random sample derived from the respondent universe for the AMI section of the FERC Survey.

Development of the FERC Survey and Sampling Design

Coordination with EIA

Commission staff coordinated with Robert Schnapp, Director, Electric Power Division, EIA, to determine what EIA information Commission staff could use to meet the requirements of EPAct 2005 and to avoid imposing redundant reporting burdens on the industry. Neither the use of EIA DR data nor revisions of existing EIA information collections were going to help Commission staff meet the statutory requirement because: (1) there was a mismatch between the data collected and the data

[4] See this Report's Chapter VI, Role of Demand Response in Regional Planning and Operations and Chapter VII, Regulatory Barriers.

Congress asked for;[5] and (2) the timetable for revising and collecting the needed data through EIA-861 did not coincide with the Congressional deadline of August 8, 2006.[6] Based on these circumstances, Commission staff concluded that a separate survey was needed.

The Draft Survey

Commission staff decided to use a voluntary rather than mandatory survey because many of the entities it would be surveying were non-jurisdictional. To design the draft survey, Commission staff received advice and assistance from Chuck Goldman and Ranjit Bharvirkar from the Lawrence Berkeley National Laboratory, the Demand Response and Advanced Metering Coalition (DRAM) and the Mid-Atlantic Demand Response Initiative (MADRI). Commission staff designed the draft survey to collect the needed information using three forms: one was to collect general and identifying information on the respondents, the second was on demand response and time-based metering programs (FERC-727), and the third was on advanced metering infrastructure (FERC-728). Dividing the FERC Survey into three sections allowed different people within an organization to collect data and complete the forms at the same time. The general information section of the FERC Survey helped link data from all parts of the FERC Survey together for each respondent. It also provided a fast way for organizations to respond to the FERC Survey if they had no information to report.

The Respondent Universe

To analyze the survey data and calculate statistics for this report, Commission staff reviewed the composition of the respondent universe (RU) very closely, and found that there were 3,365 organizations as listed in Table F-1.

Table F-1. Respondent Universe of FERC Survey

Group Name	# of Organizations in Group
Municipally Owned Utilities	1,847
Cooperative Utilities	884
Investor Owned Utilities	219
Power Marketers	165
Political Subdivisions	126
Municipal Marketing Authorities	19
Curtailment Service Providers (CSPs)	68
State Utilities	21
Federal Utilities	9
RTOs/ISOs	7
Grand Total	**3,365**

Source: EIA, Internet

[5] EIA-861 data provides total, aggregated data on energy efficiency and load management. It does not collect information on saturation and penetration rates of advanced meters, communications, technologies, devices and systems. In additon, the EIA-861 does not ask about existing demand resource programs or time-based rate programs. The form does not have detailed information on the annual resource contribution of demand resources.

[6] Per an August 21, 2005 conversation between David Kathan of FERC and Robert Schnapp of EIA, it was determined to be too late for EIA to incorporate the additional data Commission staff needed in the EIA-861 which was soon to be issued to collect 2005 data. Moreover, EIA-861 responses are due by April of each year, and EIA does not publish the results of the survey until November or December. This timetable did not allow FERC to be able to respond to Congress.

Table F-2 shows the adjustments Commission staff had to make to the number of organizations in three categories (Municipally Owned Utilities, Curtailment Service Providers (CSPs) and Regional Transmission Organization/Independent System Operator (RTO/ISO) to:

- limit the geographic scope of the survey to businesses in American States, as required by Congress;
- reflect a change in utility ownership status that occurred during the survey period;
- ensure accurate survey outreach to all organizations which might have DR or AMI activities to report; and
- eliminate data redundancy.

Specifically, Commission staff and Utilipoint made four adjustments to the number of groups in each category of the RU as they proceeded from OMB authorization to fielding and analysis. First, the organizations that received the FERC survey included a municipal utility in Guam and three utilities in the United States territories of Puerto Rico, Virgin Islands, and Samoa. Commission staff did not include the organizations in the territories that responded in the final survey tabulations, and so the number of State utilities in the RU decreased from 24 to 21, and the number of municipally owned utilities decreased from 1,847 to 1,846. In the course of fielding the survey, one investor owned utility changed to a municipal utility, which increased the number of municipally owned utilities from 1,846 back up to 1,847 and decreased the number of investor utilities from 220 to 219. Commission staff inadvertently counted four RTOs/ISOs as CSPs during its work with OMB for survey and sample authorizations. Commission staff also subsequently found that it had counted one of the CSPs three times because the company has three EIA identification numbers in the 2005 EIA 861 database used to field the FERC Survey. The necessary adjustments result in a decrease in the number of CSPs listed in the requests to OMB for survey and sample authorization (74) and in the number of CSPs who received the FERC Survey (70) to 68.

Table F-2. Adjustments to Number of Organizations in RU Groups

Group Name	# of Organizations in RU by Group	RU #s in FERC Survey Authorization Request to OMB	RU #s in FERC-Proposed Sample Design	RU #s who Received Survey
Municipally Owned Utilities	1,847	1,847	1,847	1,847
Cooperative Utilities	884	884	884	884
Investor Owned Utilities	219	220	220	220
Power Marketers	165	165	165	165
Political Subdivisions	126	126	126	126
Municipal Marketing Authorities	19	19	19	19
CSPs	68	74	74	70
State Utilities	21	24	24	24
Federal Utilities	9	9	9	9
RTOs/ISOs	7	8	0	7
Grand Total	**3,365**	**3,294**	**3,368**	**3,371**

Source: EIA, Internet

The utility component of the respondent universe consists of utilities in the United States that are involved in the generation, transmission, and distribution of electric energy. The region definition used in the FERC Survey was based on that used by the North American Electric Reliability Council

(NERC). Using NERC regions allowed collection of data based on how energy is traded and managed, and provided the most useful regional grouping for the consideration of DR resources, and advanced metering deployment that would potentially reduce barriers for participation in demand response and time-based rate programs and/or tariffs.

FERC Survey Methodology

The results in the final report reflect improvements Commission staff was able to make to the draft survey because of public comments. In addition, in order to obtain OMB approval, Commission staff had to incorporate a sample in its survey design methodology.

Public Comment

On November 3, 2005, Commission staff issued in Docket No. AD06-2-000 a notice with the proposed survey.[7] The notice was published in the November 9, 2005 *Federal Register*.[8] In seeking public comment, Commission staff asked whether the questions would elicit accurate information on advanced meters and demand response programs, or whether the questions should be modified or supplemented to better obtain information. In addition, Commission staff asked for input on other sources of information on advanced metering and demand response programs. Twenty-nine entities filed comments regarding the proposed survey.

In response to the comments, numerous changes were made including clarification of what was expected on the FERC Survey and the development of a glossary of terms. In addition, detailed instructions for completing each section of the FERC Survey were significantly revised and expanded. The FERC Survey web page was populated with information about the Commission's demand response work, including a document listing and answering frequently asked questions; related notices; the draft survey; and a Commission-staff summary of comments on the draft survey. Respondents were also able to download a copy of the entire survey instrument to help them organize and conduct their data collections and to help them complete the FERC Survey online as quickly as possible.

The structure of the FERC Survey was revised to allow respondents to enter as many as 8 demand response and/or time-based rate programs/tariffs per customer class per region. Respondents were provided with multiple choice questions in a format only requiring that respondents make a choice among options rather than enter codes. This was done to improve the quality of data and ease the burden on respondents. Other survey design enhancements included the use of tables whenever possible for respondents to be able to ensure that the numerical information provided was consistent across each customer class and routing to keep respondents from having to search for the next relevant question to answer. This feature was tested on the web before release of the survey to ensure that it worked correctly. Many of the comments revealed that potential respondents were interested in the results, understood the questions, and were very capable of discussing the issues in great detail. To allow for additional input, the FERC Survey provided comment boxes on a regular basis throughout the forms. This yielded information that could normally only have been obtained through an in-person interview.

[7] The two sections of the survey were FERC-727 "Demand Responses and Time-Based Rate Programs Survey" and FERC-728 "Advanced Metering Program Survey."

[8] 70 FR 68002-6803.

Commission staff received several comments on the draft survey regarding security and took steps to address the concerns. Commission staff issued a randomly generated, organization-specific, alpha-numeric password to ensure that the survey responses received were the official response of the organization. The letter from Commission staff with the survey provided potential respondents with their password. UtiliPoint was diligent in keeping the survey responses and data secure. Access to the FERC Survey was through a FERC webpage link that took respondents to the UtiliPoint server. UtiliPoint's server hosting company uses network intrusion detection in a signature based model. They also use a state based layer firewall with notification and alerting of abnormal events. The administrator at the server hosting company is a Certified Information Systems Security Professional.

OMB Requirements

Commission staff reviewed and met the OMB guidelines outlined in *Questions and Answers When Designing Surveys for Information Collections*. The biggest challenge Commission staff had in gaining OMB approval of the FERC Survey came from a belief OMB staff had that sending out the FERC Survey to the entire respondent universe would result in data with a self-selection bias. As a result, OMB required Commission staff to: (1) change the FERC Survey design to mitigate the potential for self-selection bias by drawing a random sample of 762 in the AMI section; (2) provide a report on the achieved response rates by strata and on the results of analyses comparing the random sample to the RU and (3) note any meaningful differences between the response rate of the AMI section of survey for the RU and for the sample of 762 in the final report to Congress. In its analysis, Commission staff found no significant self-selection bias in the data.

Methodology

Commission staff conducted the FERC Survey using the Internet. The FERC-727 and FERC-728 were posted as forms on the Commission's web page and the links allowed those who took the FERC Survey to submit their responses electronically directly to FERC and UtiliPoint.

In designing the methodology for the DR and AMI sections of the survey, UtiliPoint:

- Drew the pool of utility respondents from the 2005 EIA respondent list and verified the number of organizations in each group;
- Segmented the pool of potential FERC Survey respondents by NERC region, type of utility and the number of retail customers served;
- Sized utilities based on total number of customers each utility reported in its 2004 EIA-861 form, as follows:
    - large (number of customers over 100,000);
    - medium (number of customers > 25,000 and less than 100,000);
    - other (0 retail customers or Generation and Transmission utility) and
    - small (less than or equal to 25,000 customers); and
- Drew a random sample of 762 for the AMI section of the survey.

Commission staff expected that the DR program/tariff offerings as well as the penetration of AMI would be substantially different across the different size utilities and across the different types of utilities.

The AMI survey methodology anticipated responses from utilities that have ownership and/or responsibility for revenue and billing metering, such as cooperative, federal, investor owned, municipal, political subdivision, and state utilities who serve retail customers.

Utilities that do not serve retail customers—namely Municipal Marketing Authorities, Wholesalers or Generation and Transmission (G&T) utilities—were not expected to submit responses for the AMI section of the FERC Survey since these types of utilities typically do not own or have responsibility for billing and revenue meters for retail customers. In addition, Power Marketers (which include Competitive Retailers, Energy Service Providers, Retail Providers, and the other names generally used in regions with retail competition or retail choice) were not expected to submit responses to the AMI section of the FERC Survey because these utilities typically do not own or have responsibility for retail metering.

Fielding the FERC Survey and Analyzing the Data

Efforts to Maximize Response Rates

Commission staff tried to maximize response rates by using an aggressive outreach approach of addressing large gatherings of organizations that were expected to respond to the FERC Survey. For example, Commission staff announced preliminary survey plans to and discussed with several trade and state associations including members and/or representatives of the National Association of Regulatory Commissioners, American Public Power Association, Edison Electric Institute, and the National Rural Electric Cooperative Association. In a cooperative spirit and in consideration of the authority that state utility commissioners have in this matter, Commission staff sent letters to state regulators over FERC Chairman Kelliher's signature informing them of the organizations in their state that were asked to participate in the FERC Survey. The letter committed to giving them a status report of whether or not those utilities in their jurisdiction had responded to the FERC Survey. Commission staff sent the follow-up letters to the state regulators 30 days after the FERC Survey issued.

Another effort to maximize response was that the letter Commission staff sent to the respondent universe used personalized greetings, provided information about the FERC Survey, gave general guidance on how to complete the FERC-727 and FERC-728 and referred to the potential respondent company by name to encourage its participation in the important study. Commission staff sent the FERC Survey letter via email as well as in hard copy. Delivery of a hard copy of the FERC Survey package at the place of business was especially useful because Commission staff anticipated contacts listed in the 2005 EIA-861 data base may have changed.

Commission staff also worked to maximize response rates through the FERC Survey's design. The FERC Survey included routing to only show the respondent relevant questions, used multiple choice questions where feasible, and kept validity checking to a minimum to reduce respondent frustration during the data entry process.

To accommodate respondents who were not comfortable completing a web survey or who did not have access to the internet, the instructions provided a person's name and contact information so they could find an alternative means for reporting their information. Respondents needing such accommodation received an email telling them the links to the FERC Survey web page to print the forms. The email included instructions for completing submitting the FERC Survey manually. Respondents were able to have someone fill out the FERC Survey for them during a phone call, if they chose to. There was a phone number at the bottom of each page of the FERC Survey for respondents to call if they encountered problems while filling out the survey and this boosted response rates by solving technical difficulties which might have discouraged respondents. For example, some respondents notified Commission staff and Utilipoint that they were not able to access the information on the web site. Investigation of the matter found that these respondents had pop-up ad blockers on their computers. By disabling this feature on their computer, they were able to complete the survey. Commission staff and Utilipoint collected and compiled this sort of information into a frequently asked question list which was then posted on the survey web page.

Commission staff accommodated people at organizations with no internet by preparing and mailing copies of the FERC Survey and all the information needed to complete the FERC Survey to them.

To increase the likelihood of getting survey responses from contacts listed in the EIA-861 data base who were responsible for reporting on three or more organizations, Commission staff sent customized letters to these contacts. The letter included a spreadsheet they could use to report their data and eliminated the need to fill out the multi-page survey repeatedly.

Commission staff and Utilipoint followed through with those who had not completed the FERC Survey by the deadline by phoning them and filling out the relevant survey sections for them while they were on the phone. People who did all the follow-up had experience in interviewing energy market participants and had a deep knowledge of advanced metering, demand response, and time-based rates.

UtiliPoint tracked responses as they came in to assess which NERC regions might have been showing under-representation and targeted these for early follow-up.

Expected and Actual Response Rates

With regard to expected response rates in general, Commission staff expected that large utilities would be very responsive and medium sized utilities less so. Small utilities were expected to be very responsive, but primarily if someone followed up with a phone call.

The response rate for the demand response and time-based programs/tariffs section of the FERC survey was expected to be lower than for the AMI survey section for two reasons. First, utilities were going to need to submit fewer responses for this FERC Survey section since only one response was required per NERC region, whereas for the AMI survey section, one response was required per state. Large utilities with operations across states were to complete an AMI survey section for each state but were to provide only one response for the FERC Survey section on DR. The second reason for anticipating a lower response rate was that longer surveys have lower response rates. The actual response rates between the two sections were almost identical.

Commission staff expected—and received—a large number of responses from larger utilities for two reasons. First, larger utilities have consistently reported more demand response load in MW than smaller utilities. Second, large utilities had shown a keen interest in the demand response section of the FERC Survey.

Commission staff also expected a high response rate from the larger utilities on the AMI section survey design for three reasons. First, the larger utilities represent more retail customers. Second, the large utilities showed a keen interest in the AMI section of the FERC Survey in their responses to the

Commission's draft survey. Third, Commission staff gave follow-up to non-responding, large utilities a high priority.

The percentage of responses by utility size was consistent with UtiliPoint survey experience that large utilities are typically very responsive and medium sized utilities less so. Experience also had showed that small utilities are very responsive, but primarily if someone follows up with a phone call. The large number of small utilities limited the number of non-responding small utilities that could be economically included in planned follow-up.

The follow-up calls were planned to first go to larger utilities since they represent the most meters per response, and then to any market segment that was having a lower than expected response rate.

Commission staff achieved a very significant—and rare—response rate greater than 50% for the small cooperative and municipally owned utilities. Small municipals usually have a voluntary survey response rate of 5 %. Table F-3 displays the response rates received.
In spite of follow up phone calls and in-person conversations with staff and leaders at all levels of the CSPs, Commission staff was only able to achieve a response rate for CSPs that was 29% for the DR section the FERC Survey and 28% for the AMI section of the FERC Survey.

During the analysis phase of the FERC Survey, experienced industry analysts reviewed the data provided by the respondents. The data was carefully weighted based on the type of organization, size, and region, to allow analyses of the responses to accurately reflect the entire market. The industry analysts tabulated the data to provide meaningful and interesting information for the report to Congress.

The FERC Survey response rate—overall and by strata—showed no statistically significant evidence of self-selection bias when Commission staff and Utilipoint compared the response rates of the 762 organizations in the random AMI sample to the response rates of the 1,860 in the respondent universe who completed the AMI section of the FERC Survey. Table F-4 displays the expected and actual response rates for AMI.

There were various categories of the ways in which organizations reported their information. In the most straightforward response, organization A submitted a DR and/or an AMI survey response for organization A. Other responses were sometimes more complicated in the organizations they covered. For example, in some cases Organization B submitted DR and or AMI responses for organization B that included the information for the organization A. This occurred when there were multiple operating companies within a particular NERC region for one entity. In other cases Organization A submitted a General Information for organization A indicating no DR and/or AMI programs. Organization B submitted a General Information for organization B indicating no DR and/or programs for Organization B. Organization A and B are separate operating companies for one entity. In yet other cases, Commission staff and Utilipoint received an email from a responsible authority indicating that organization A no longer is in business, or was never a separate entity. In a follow-up phone call with organization A, we learned they offered no DR programs and/or had no AMI. We always asked them to fill out the General Information section of the survey, and mostly did, but some did not.

Table F-3. Expected and Actual Response Rates of the Respondent Universe

Ownership	Size	Nbr of Orgs	Cell Response Goal	DR Survey Section	AMI Survey Section	Response Rate Goal	DR Response Rate	AMI Response Rate
Municipal	Large	17	14	13	12	85%	76%	71%
	Medium	84	58	49	48	70%	58%	57%
	Small	1,738	1,421	878	871	82%	51%	50%
	Wholesaler or G&T	6	5	4	4	80%	67%	67%
	XMultiRegion	2	0	1	1	0%	50%	50%
Municipal Total		***1,847***	***1499***	***945***	***936***	***81%***	***51%***	***51%***
Cooperative	Large	19	18	17	17	95%	89%	89%
	Medium	180	133	102	98	74%	57%	54%
	Small	625	478	361	352	77%	58%	56%
	Wholesaler or G&T	59	47	40	40	80%	68%	68%
	XMultiRegion	1	0	1	1	0%	100%	100%
Cooperative Total		***884***	***676***	***521***	***508***	***77%***	***59%***	***57%***
Investor Owned	Large	109	98	108	103	90%	99%	94%
	Medium	18	16	15	15	90%	83%	83%
	Small	59	53	54	55	90%	92%	93%
	Wholesaler or G&T	33	30	29	30	90%	88%	91%
Investor Owned Total		***219***	***197***	***206***	***203***	***90%***	***94%***	***93%***
Power Marketer	Large	10	6	5	6	60%	50%	60%
	Medium	5	5	3	2	100%	60%	40%
	Small	42	25	18	19	60%	43%	45%
	Wholesaler or G&T	49	29	21	20	60%	43%	41%
	XMultiRegion	59	35	33	33	60%	56%	56%
Power Marketer Total		***165***	***101***	***80***	***80***	***61%***	***48%***	***48%***
Political Subdivision	Large	7	7	6	6	100%	86%	86%
	Medium	11	11	7	6	100%	64%	55%
	Small	83	40	47	46	48%	57%	55%
	Wholesaler or G&T	25	20	14	15	80%	56%	60%
Political Subdivision Total		***126***	***78***	***74***	***73***	***62%***	***59%***	***58%***
Municipal Marketing Authority	Wholesaler or G&T	19	15	11	11	80%	58%	58%
Municipal Marketing Authority Total		***19***	***15***	***11***	***11***	***80%***	***58%***	***58%***

Ownership	Size	Nbr of Orgs	Cell Response Goal	DR Survey Section	AMI Survey Section	Response Rate Goal	DR Response Rate	AMI Response Rate
CSP	Small	68	54	20	19	0%	29%	28%
CSP Total		***68***	***54***	***20***	***19***	***80%***	***29%***	***28%***
State	Large	2	2	2	2	100%	100%	100%
	Medium	1	1	1	1	100%	100%	100%
	Small	6	6	6	6	95%	100%	100%
	Wholesaler or G&T	12	12	8	9	100%	67%	75%
State Total		***21***	***21***	***17***	***18***	***99%***	***81%***	***86%***
Federal	Small	6	6	4	4	100%	67%	67%
	Wholesaler or G&T	3	3	2	2	100%	67%	67%
Federal Total		***9***	***9***	***6***	***6***	***100%***	***67%***	***67%***
RTOs/ISOs	Small	7	6	6	6	0%	86%	86%
RTOs/ISOsTotal		***7***	***6***	***6***	***6***	***80%***	***86%***	***86%***
Grand Total		***3,366***	***2,656***	***1,886***	***1,860***	***79%***	***56%***	***55%***

Source: FERC Survey