Demand Response & Smart Grid—State Legislative and Regulatory Policy Action Review: October 2008 – May 2010

An Overview

Prepared by the Demand Response Coordinating Committee (DRCC)

June 2010

DRCC DEMAND RESPONSE COORDINATING COMMITTEE

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Acronyms

AMI = Advanced Metering Infrastructure

CAISO = California ISO

C&I = Commercial and Industrial

DSM = Demand-Side Management

EPACT = Energy Policy Act

EPS = Energy Efficiency Portfolio Standard

ERCOT = Electric Reliability Council of Texas

FERC = Federal Energy Regulatory Commission

GHG = Greenhouse Gas

IRP = Integrated Resource Plan

ISO = Independent System Operator

M&V = Measurement and Verification

NOPR = Notice of Proposed Rulemaking

NYISO = New York ISO

PHEV = Plug-in Hybrid Electric Vehicle

PJM = PJM Interconnection, the RTO in the Mid-Atlantic region

PURPA = Public Utility Regulatory Policies Act

RFP = Request for Proposals

RPS = Renewable Energy Portfolio Standard

RTO = Regional Transmission Organization

RTP = Real-Time Pricing

SPP = Southwest Power Pool, the RTO for the southwestern region of the US

TOU = Time of Use

Overview

"Demand Response & Smart Grid—State Legislative and Regulatory Policy Action Review: October 2008 – May 2010" is an overview of state-level legislative and regulatory policy developments on demand response, smart metering, and smart grid. It has been prepared by the Demand Response Coordinating Committee (DRCC) as an update to the DRCC's 2008 policy survey, "Demand Response and Smart Metering Policy Actions Since the Energy Policy Act of 2005: A Summary for State Officials," prepared for The National Council on Electricity Policy. That report covered state and federal policy developments during the period between 2005 and mid-year 2008 and gave special attention to state implementation of the demand response and smart metering provisions—Section 1252—of the Energy Policy Act of 2005 (EPACT). The new report continues to cover EPACT 2005 implementation efforts as well as the consideration by state regulatory commissions of the two smart grid PURPA Standards established by the Energy Independence & Security Act of 2007. In addition, the updated report catalogues regulatory commission action independent of federal policy as well as state legislative activity and efforts by state agencies. It does not cover any federal activity. That will be the subject of a separate report.

Regarding the methodology and scope of "Demand Response & Smart Grid—State Legislative and Regulatory Policy Actions: October 2008 – May 2010":

- It is based on the best public information that was available as of May 2010 rather than on an in-depth state-by-state investigation. Accordingly, and because of the rapid pace of demand response and smart grid developments, this report may not contain all relevant policy activities.

- It is designed to summarize policy developments and not provide opinion or commentary. It includes neither analysis nor predictions regarding potential outcomes of policy developments.

- It describes policy developments on energy efficiency, renewable energy, or other areas only when they directly mention demand response, smart grid, smart meters, AMI, or other pertinent subjects. Accordingly there may have been policy developments in those other areas (or in other areas such as state facilities, budgeting, or tax policy) that can have an impact on demand response and/or smart grid but that are not captured by this report.

- It includes information that was presented in the DRCC's 2008 policy survey, "Demand Response and Smart Metering Policy Actions Since the Energy Policy Act of 2005," *only* if there are updates to what was reported previously.

- It does not provide links to legislation or other policy documents described.

- The process of developing the report had three stages of research. The first stage consisted of reviewing the DRCC's archive of demand response and smart grid policy and legislative activity. The next step was to revisit sources and to review the documentation of the known activity—mostly regulatory proceedings and legislation—to determine whether there had been any additional developments. The final stage was to investigate any leads to identify policy or legislative activity previously unknown by the DRCC.

This report demonstrates that a substantial amount of state policymaking related to demand response and smart grid has happened recently or is presently underway. It also reflects the great diversity of approaches taken by states and the many levels of activity.

The "Demand Response & Smart Grid—State Legislative and Regulatory Policy Action Review: October 2008 – May 2010"—as well as the DRCC's 2008 "Demand Response and Smart Metering Policy Actions Since the Energy Policy Act of 2005: A Summary for State Officials"—can be accessed on the DRCC's website.

http://www.demandresponsecommittee.org/reports.htm

The Demand Response Coordinating Committee (DRCC) is a non-profit organization formed in 2004 to increase the knowledge base in the U.S. on demand response and smart grid and to facilitate the exchange of information and expertise among practitioners and policymakers.

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State Policy Activities

Alabama

No legislative or regulatory policy activity during the review period was known to the reviewers.

Alaska

No legislative or regulatory policy activity during the review period was known to the reviewers.

Arizona

REGULATORY:

EPACT 2005

In July 2007 the Arizona Corporation Commission Decision adopted a modified version of PURPA Standard 14 ("Time-Based Metering and Communications") as enacted in EPACT 2005. In January 2009 both Sulphur Springs Valley Electric Cooperative and Trico Electric Cooperative filed an update about their efforts to introduce time-based rates and smart metering, thereby complying with the July 2007 Decision. The Commission's modified Standard 14 applies the PURPA standard to all electric distribution companies within its purview instead of only to companies with retail sales of more than 500,000 MWh, as specified in the original language in the EPACT statute. The Commission's version of EPACT 1252 reads:

> "Within 18 months of Commission adoption of this standard, each electric distribution utility shall offer to appropriate customer 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. Within 18 months of Commission adoption of this standard, each electric distribution utility shall investigate the feasibility and cost-effectiveness of implementing advanced metering infrastructure for its service territory and shall begin implementing the technology if feasible and cost-effective."

Commission Approves IRP Rules

The Arizona Corporation Commission announced in Mary 2010 that it had adopted rules establishing an Integrated Resource Planning process for the state's electric utilities. Under the new rules, every two years utilities will fill a 15-year IRP. Each IRP is to specify sources of generation as well as the amount of demand response, energy efficiency, and renewable energy to be used. Furthermore, IRPs are to address how utilities are falling in line with the Arizona's Renewable Energy Standard. The Commission has sent its approved rules to the state's Attorney General for final endorsement.

LEGISLATIVE:

No legislative policy activity during the review period was known to the reviewers.

Arkansas

REGULATORY:

EPACT 2005

The Arkansas Public Service Commission decided in August 2007 not to adopt PURPA Standard 14 ("Time-Based Metering and Communications") as enacted in EPACT 2005. In the course of its proceeding to consider the standard, however, it directed utilities to file—and later approved—“quick start and/or pilot” efficiency programs to run through 2009. Some of these programs included demand response. In March 2009, the Commission issued an Order directing all investor-owned utilities to file a Comprehensive Energy Efficiency Plan that would build upon the “quick start” programs. Such plans were filed in July 2009. Later in the month, the Commission ordered that each utility provide additional information, such as budget projections and demand- and energy-savings goals. In that Order, the Commission said that utilities should distinguish between demand response and energy efficiency programs.

Energy-Efficiency Roadmap

In February 2010 the Arkansas Public Service Commission issued a “roadmap” Order “largely approving” energy-efficiency plans and budgets filed by four electric utilities, three natural gas utilities, and the administrators of the state weatherization and energy-efficiency education programs. In the Order, the Commission shifted consideration of demand response and smart grid issues to a separate docket focused on “Sustainable Energy Resources.” In that proceeding, the Commission also issued an Order in February 2010. That Order required utilities “to report in detail on their current use of and future plans for Smart Grid, DR, and AMI projects and investments in Arkansas”. Utilities were to file these reports in March 2010. The Commission indicated its intention to resolve this inquiry by the end of 2010.

LEGISLATIVE:

No legislative policy activity during the review period was known to the reviewers.

California

REGULATORY:

Long Term Procurement Plans

In February 2008, the California Public Utilities Commission opened a proceeding to consider the “policies, practices and procedures” of establishing long-term procurement plans. The CPUC noted that a main focus of the proceeding would be the implementation of the Energy Action Plan loading order, “in the order of EE, demand response (DR), renewables, distributed generation, and clean fossil-fuel." Workshops were held in April and May 2008.

In a July 2009 Scoping Ruling, the Commission published its Staff's "Straw Proposal on LTPP Planning Standards" and solicited comments about it. It also scheduled a workshop for August 2009.

In December 2009 the proceeding's ALJ issued a Ruling suspending the proceeding's schedule of activities and informing parties of the recommendation "that the Commission develop and initiate two new Rulemakings as successors to this proceeding" in order to allow "more immediate issues related to utility-specific procurement plans for 2010 to be addressed separately."

<u>EISA 2007 and State Smart Grid Policy</u>

In a December 2008 Order Instituting Rulemaking (OIR) the California Public Utilities Commission initiated a proceeding to consider adopting the two smart grid PURPA Standards established by the Energy Independence & Security Act of 2007. The OIR also outlined the Commission's intent to consider the state's policies for the smart grid. The scope of the proceeding, however, extends beyond the smart grid to what the smart grid enables, including greater deployment of demand response. Initial comments were filed in February 2009 and reply comments were filed in March 2009. Later in the March 2009, the Commission held a prehearing conference for the proceeding and a workshop about how the American Recovery and Reinvestment Act 2009 might influence it. Guiding the conference was the question of whether to divide the proceeding into phases in order to address separately the PURPA Standards of EISA and the "opportunities that arise from ARRA."

In April 2009, the Commission and members of the California Energy Commission held a "Smart Grid Symposium" in effort to "provide policy makers a forum to hear the relevant and latest information surrounding developments of Smart Grid systems for energy utilities." The goal of the hearing was to disseminate "contextual information" that would inform possible smart grid policies and regulations.

In May 2009 the Commission issued a Scoping Memo adopting the procedural scope described in the December 2008 OIR and adding to it the smart grid "issues and financing opportunities" created by the passage of ARRA 2009. It also set the goal "to develop a regulatory policy that clearly delineates the policy direction the Commission wants utilities to take and states how this Commission will evaluate proposals that seek to advance these policies." It posed three overarching policy questions to guide the proceeding:

(1) “What policy goals, if any, will the development of a Smart Grid in California advance?”
(2) “How should the Commission measure progress toward development of a Smart Grid, i.e. what are appropriate metrics?”
(3) “What regulatory approach should the Commission use to make progress toward developing a smarter grid in a manner that is in the public interest?”

From May 2009 through July 2009 Commission held five workshops.

Later in May 2009 the Commission issued a Ruling in which it amended the proceeding’s scope with respect to the DOE smart grid grants funded under the ARRA 2009.

In December 2009 the Commission issued a Decision in which it declined to adopt the Smart Grid Investment PURPA Standard and the Smart Grid Information PURPA Standard established by EISA 2007. The rationale for declining the investment standard is that “California policy is already largely consistent with these requirements and further action would produce confusion and costs that do not advance the purposes of the act.” The reason for passing on the investment standard is that “prior Commission actions constitute a ‘prior state action’” and, according to EISA 2007, no further action is necessary.

The December 2009 Decision, however, did adopt policies for Southern California Electric, Pacific Gas & Electric, and San Diego Gas and Electric that support smart metering, smart grid, and demand response:

- “Southern California Edison Company, San Diego Gas & Electric Company, and Pacific Gas and Electric Company shall provide an authorized third party with access to the customer’s usage information that is collected by the utility by the end of 2010 should the customer desire that information.”

- “Southern California Edison Company, San Diego Gas & Electric Company and Pacific Gas and Electric Company shall provide to their customers with a smart meter access to usage data on a real-time or near real-time basis no later than the end of 2011. . . .”

- “The next phase of this proceeding shall consider rules to provide customers and third parties with access to usage and price data consistent with Energy Information and Security Act of 2007 standards, the general public interest, and state privacy rules.”

In February 2010 the Commission issued a Ruling that revised the procedural schedule and amended the scope of the proceeding so as to include the smart grid issues the Commission is to consider per legislation signed by Governor

Schwarzenegger in October 2009. This law (SB 17) directs IOUs and municipal utilities to file smart grid deployment plans with the Commission by July 2011. The Commission, meanwhile, is responsible for establishing by July 2010 the requirements for such deployment plans.

In March and April 2010, comments and reply comments were filed about three topics: (1) the requirements of SB 17; (2) the Commission's effort, in compliance with its December 2009 Decision to decline the PURPA standards of EISA 2007, to "consider rules to provide customers and third parties with access to usage and price data consistent with Energy Information and Security Act of 2007 standards, the general public interest, and state privacy rules"; and (3) the Commission's December 2008 Order Instituting Rulemaking (OIR) establishing the proceeding, which called for "policies to promote California's Smart Grid infrastructure."

The Commission held two workshops in March 2010, focusing on "Smart Grid Deployment Plan Requirements" and "Access to Electricity Prices & Usage Workshop."

In May 2010 the Commission issued a Proposed Decision that would provide Southern California Edison, San Diego Gas & Electric, and Pacific Gas & Electric with guidance for filing smart grid deployment plans in compliance with Senate Bill 17. The Proposed Decision would order the following:

- Smart grid deployment plans "shall follow an eight-element format": (1) Smart Grid Vision Statement; (2) Deployment Baseline; (3) Smart Grid Strategy; (4) Grid Security and Cyber Security Strategy; (5) Smart Grid Roadmap; (6) Cost Estimates; (7) Benefits Estimates; and (8) Metrics.

- The "Smart Grid Vision Statement section" of the deployment plans "shall address how the grid can achieve the following policies contained in Senate Bill 17": (1) Be self-healing and resilient; (2) Motivate consumers to actively participate in the operations of the grid; (3) Resist attack; (4) Provide higher quality of power and avoid outages; (5) Accommodate all generation and storage options; (6) Enable electricity markets to flourish; (7) Run the grid more efficiently; and (8) Enable penetration of intermittent power generation sources.

- "Each Smart Grid Vision Statement must also include three sections addressing: (a) Smart Market; (b) Smart Customer; and (c) Smart Utility."

- The deployment plans shall include "an inventory of current Smart Grid infrastructure investments and a baseline assessment of privacy and security issues affecting the Smart Grid."

- The deployment plans shall include “a Smart Grid Strategy section that demonstrates how a utility can achieve the goals in Senate Bill 17 and promote the goals of General Order 156. In addition, the Smart Grid Strategy section must consider whether using existing communications infrastructure can reduce the costs of deploying the Smart Grid. The Smart Grid Strategy section must also consider how interoperability standards will be used and how the utility will minimize the risk of stranded costs in cases where consensus standards do not yet exist.”

- The Smart Grid Strategy section of the deployment plans shall recommend “the adoption of communications protocols and interoperability standards.”

- The deployment plans shall include “a section on Grid Security and Cyber Security Strategy.”

- The section on Grid Security and Cyber Security Strategy in the deployment plans shall include “a systematic risk assessment that addresses the prevention of, preparation for, protection against, mitigation of, response to, and recovery from security threats for its advanced metering infrastructure distribution grid management, and Smart Grid operations.”

- The deployment plans shall include “a Smart Grid Roadmap that projects the timing of the utility’s Smart Grid investments.”

- The Cost Estimate section of the deployment plan shall include “estimated costs for the Smart Grid for the next five years.”

- The utilities “shall seek approval of Smart Grid investments either through an application filed no sooner than the filing of its Smart Grid deployment plan or through General Rate Cases.”

- The utilities “shall file an annual report in Rulemaking 08-12-009 on the status of Smart Grid investments commencing October 1, 2012 and annually thereafter through October 1, 2020.”

The Commission has reported its expectation to resolve this proceeding by August 2010.

<u>2009 Integrated Energy Policy Report</u>

In December 2009 the California Energy Commission published its “2009 Integrated Energy Policy Report.” The report includes a set of recommendations for demand response and smart metering:

- “All utilities, including publicly owned utilities, should install meters capable of recording hourly consumption and should publish their time-varying electric rates in an actionable and open source format. Status reports on the progress of meter installation should be included in the *2011 Integrated Energy Policy Report (IEPR)*.”

- “All customers with advanced meters should have no-cost access to near real-time information about their energy use in a format that is both meaningful and easy to understand.”

- “All utility price signals should use open source, nonproprietary formats.”

- “The Energy Commission will continue efforts to adopt a statewide load management standard requiring all utilities in the state to adopt default but optional time-varying pricing for customers that have advanced meters. In developing load management standards, the Energy Commission will continue collaboration with the CPUC, the California Independent System Operator (ISO), and publicly owned utilities.”

- “The Energy Commission’s Public Interest Energy Research program will continue to pursue research and development that supports load management standards.”

It also addresses the smart grid, though in the context of supporting the integration of renewable resources. Regarding the smart grid, it recommends:

- “The Energy Commission will work with the CPUC to develop a regulatory framework for adopting National Institute of Standards and Technology (NIST) Smart Grid interoperability and cyber security standards consistent with Federal Energy Regulatory Commission rulings to ensure national and international compatibility.”

- “The Energy Commission, the CPUC, and the California ISO should participate in the NIST Smart Grid Interoperability Panel to ensure that California smart grid activities are shared nationally and that California can learn from smart grid activities in other states. In addition, there should be continued coordination with NIST on smart grid standards such as Open Automated Demand Response.”

- “The Energy Commission will continue to coordinate with the CPUC, the California ISO, utilities, and stakeholders to develop smart grid plans, consistent with the requirements in SB 17 (Padilla, Chapter 327, Statutes of 2009), as described in Chapter 1.”

- "The Energy Commission will continue Public Interest Energy Research program research on technologies that mitigate or resolve intermittency of renewable resources, as well as research on bidirectional power flows and power quality issues resulting from increased use of renewable resources."

A January 2009 Order outlined the scope of the 2009 report, noting that it should "identify research and development efforts on smart grid, energy smart communities, and distribution level renewables to facilitate and support increased integration of renewables resources." In May 2009 the Commission held a two-day workshop that addressed how the smart grid could support the state's RPS goal of 33% renewable energy by 2020.

In April 2010 the Commission issued an Order establishing the general scope and schedule for the "2010 Integrated Energy Policy Report Update." The Order indicated that the main focus of the report would be on "California's transition to a clean energy economy and the contribution of American Recovery and Reinvestment Act of 2009 (ARRA) funding to that transition." The document will address demand response and smart grid, and it is to be adopted by November 2010.

<u>Utilities' 2009 – 2011 Demand Response Programs and Budgets</u>

In August 2009 the California Public Utilities Commission issued a Final Decision adopting the 2009 – 2011 "demand response activities and budgets" filed in June 2008 by Southern California Edison (SCE), San Diego Gas & Electric (SDG&E), and Pacific Gas & Electric (PG&E). The Decision approved the continuation of some demand response programs, modified others, and discontinued several. It also authorized new pilot programs and the funding for evaluation, measurement, and verification activities. In addition, it accepted budgets; established a settlement baseline; extended existing cost-recovery mechanisms; and set rules on concurrent participation in multiple programs. Finally, it directed the three utilities to work on developing a permanent load-shifting program. Highlights from the August 2009 Final Decision include:

Southern California Edison

- "Southern California Edison Company shall continue the following existing demand response programs, as described in this decision: the Base Interruptible Program, the Optional Binding Mandatory Curtailment Program, the Scheduled Load Reduction Program, the Demand Bidding Program, the Capacity Bidding Program, Critical Peak Pricing, Real Time Pricing, Technical Assistance and Technology Incentives, Emerging Markets and Technology, Automated Demand Response, the Summer Discount Plan, Agricultural

Pumping – Interruptible, Rotating Outage Program, and the Agricultural Pump Timer Program."

- "Southern California Edison Company's proposal to implement an Energy Options program is approved. Southern California Edison Company shall transition participants in its Demand Bidding Program and Capacity Bidding Program into this program, as proposed, and shall discontinue those programs when the transition is complete."

- Southern California Edison is authorized to operate the following pilots in 2010 and 2011: "the Smart Thermostat Customer Experience Pilot and the Optional Programmable Communicating Thermostat Pilot."

Pacific Gas & Electric

- "Pacific Gas and Electric Company shall continue the following existing demand response programs, as described in this decision: the Base Interruptible Program, the Optional Binding Mandatory Curtailment Program, the Scheduled Load Reduction Program, the Demand Bidding Program, the Capacity Bidding Program, Critical Peak Pricing, Real Time Pricing, Technical Assistance and Technology Incentives, Emerging Markets and Technology, Automated Demand Response, SmartAC, SmartRate, and PeakChoice."

- Pacific Gas and Electric Company is authorized to operate the following pilots in 2010 and 2011: "the Commercial and Industrial Intermittent Resource Pilot and the Hybrid Electric Vehicle/Electric Vehicle Smart Charging Pilot."

- "Pacific Gas and Electric Company shall discontinue the Base Interruptibles Program Option B and the Business Energy Coalition and the Automated Business Energy Coalition."

- "Pacific Gas and Electric Company's requests to issue a Request for Proposal in 2011 to solicit more demand response contracts for the 2012 – 2014 period are denied."

San Diego Gas & Electric

- "San Diego Gas & Electric Company shall continue the following existing demand response programs, as described in this decision: the Base Interruptible Program, the Optional Binding Mandatory Curtailment Program, the Scheduled Load Reduction Program, the Demand Bidding Program, the Capacity Bidding Program, Critical Peak Pricing, Real Time Pricing, Technical Assistance and Technology Incentives, Emerging Markets and Technology, Automated Demand Response, Critical Peak Pricing – Emergency, and Summer Saver programs."

- San Diego Gas & Electric is authorized to operate the following pilot in 2010 and 2011: "the Residential Automated Controls Pilot."

- "San Diego Gas & Electric Company shall transition its Demand Bidding Program participants onto its Critical Peak Pricing Tariff, as proposed, and shall discontinue the Demand Bidding Program when the transition is complete."

- "San Diego Gas & Electric Company shall discontinue its Peak Day Credit Program within 30 days of the effective date of this decision."

Automated Demand Response

- "Utilities shall evaluate the results of their Automated Demand Response activities. . . . The utilities shall report the results of these evaluations to the Energy Division Director by September 30, 2010, and provide copies to the most recent service list in this proceeding. . . . The utilities shall jointly hold two workshops on these results, one to present and discuss their findings and solicit feedback from the parties and a second public workshop to present proposals based on the results of the first workshop and solicit feedback and other proposals from the parties."

CAISO Integration

- "The plans proposed by Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company to transition demand response activities to integrate into the new CAISO markets during 2009-2011 are approved with the following modifications. . . ."

Baseline

- "All demand response programs of Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company utilizing a baseline for settlement purposes shall use a 10-day individual customer baseline with a day-of adjustment. . . ."

Permanent Load Shifting

- "Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall work with parties to examine ways of expanding the availability of permanent load shifting. This study shall include discussion of a standard offer proposal that could apply generally to any permanent load shifting technologies including, but not limited to, thermal energy storage. This study should also consider other ways of encouraging permanent load shifting, including modifications to time of use rates or another RFP process."

Evaluation, Measurement and Verification

- "The Demand Response Measurement and Evaluation Committee shall continue its oversight of demand response evaluation, measurement and verifications activities. Beginning with the evaluation of 2009 demand response programs, the Demand Response Measurement and Evaluation Committee shall oversee not only the evaluation of statewide demand response activities, but also the evaluation of activities conducted by Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company."

The three utilities are to file by January 2011 their demand response applications for 2012 – 2014.

California Climate Adaption Strategy

In December 2009 the California Natural Resources Agency released its "2009 California Climate Adaptation Strategy," which "summarizes the best known science on climate change impacts in the state to assess vulnerability and outlines possible solutions that can be implemented within and across state agencies to promote resiliency." The strategy mentions peak demand and the smart grid, but just once. It also notes demand response, though only in the context of California's loading order:

- "Energy strategies such as smart grid technologies also aim to improve the ability of the electricity system to respond to peak demands."

- "In addition, transmission of electricity is less efficient during hotter periods, leading to electricity deficits especially during peak demand times."

- "Adaptation strategies reflect the 'loading order,' a state energy policy which calls for meeting new electricity needs first with energy efficiency and demand response; second, with new generation from renewable energy and distributed generation resources; and third, with clean fossil-fueled generation and transmission infrastructure improvements.

33-by-20 RPS

In September 2009 Governor Schwarzenegger signed an Executive Order directing the California Air Resources Board (ARB) to implement by July 2010 regulations that would realize the state's RPS of 33% by 2020. The Executive Order calls for the regulations to complement demand response and energy storage:

> "That the PUC [Public Utilities Commission] and the CEC [California Energy Commission] are requested to provide advice and assistance to, and cooperate with, the ARB in its consideration and implementation of a regulation to reduce greenhouse gas emissions through the creation and use of renewable energy sources. The ARB may delegate to the PUC and the CEC any policy development or program implementation responsibilities that would reduce duplication and improve consistency with other energy programs such as demand response, energy efficiency and energy storage."

It also directs ARB to work with CAISO to ensure that the RPS regulations are consistent with reliability needs and the wholesale electricity market:

> "That the ARB shall consult with the Independent System Operator and other load balancing authorities on, among other aspects, impacts on reliability, renewable integration requirements and interactions with wholesale power markets in carrying out the provisions of this Executive Order."

The Governor established the 33-by-20 RPS via a November 2008 Executive Order. In May 2009 he called on the state legislature to pass legislation that would put the RPS info effect.

California Energy Commission Adds Flywheel Storage to Wind-Power Pilot

In March 2010 the California Energy Commission added a flywheel energy storage system to its wind-power demonstration project in Tehachapi, California. The flywheel storage is to provide frequency regulation and is to "alleviate the constraint" during periods of grid stress. CAISO and Southern California Edison are "leading stakeholders" in the Commission's wind-power pilot.

Proceeding to Investigate Rise in Disconnections

In February 2010 the California Public Utilities Commission issued an Order initiating a rulemaking proceeding to "address the issue of customers' electric and natural gas service disconnection." The move followed an increase in disconnections, jumping to "28% statewide from September 2008 to August 2009, compared with the previous 12 months," according to a February 2010 Los Angeles Times story. Reportedly, the California Division of Ratepayer Advocates attributed this increase to the new smart meters being deployed by the state's three IOUs. Comments and reply comments were filed with the Commission in March and April 2010. The Commission has reported that it plans to issue a Proposed Decision in June 2010.

IOUs Demand Response Proceeding

Since January 2007 the California Public Utilities Commission has been conducting a proceeding to address specific issues related to developing effective demand response programs for investor-owned utilities in California—namely, Southern California Edison (SCE), San Diego Gas & Electric (SDG&E), and Pacific Gas & Electric (PG&E). The proceeding so far has had three phases.

Phase I ended in April 2008 when the Commission issued an Order adopting the "Demand Response Load Impact Estimation Protocols" for the utilities, which the proceeding's ALJ had recommended, via a Proposed Decision, in March 2008. Phase I focused on measurement and evaluation protocols and "methodologies related to existing and possible future DR activities."

Phase II of the proceeding began in October 2007 in effort to set goals for demand response. The Commission solicited comments about whether "existing emergency-triggered DR programs should be modified to facilitate their integration into CAISO's Market Redesign and Technology Upgrade (MRTU)." Comments were filed in June and July 2008.

Phase III began in July 2008 when the Commission decided to address the "operation of the investor-owned utilities' emergency-triggered DR programs in the future electricity wholesale market." A prehearing conference was held in August 2008. Workshops were held in August and October 2009, focusing, respectively, on "the optimal size for emergency-triggered DR programs in each IOU's service area to maintain grid reliability" and "alternatives to emergency-triggered DR programs." In January 2010, the Commission held a settlement conference. In February 2010 a joint motion proposing the adoption of a settlement was filed. The Settling Parties proposed "changes to the emergency-triggered and reliability-triggered DR programs that will make the programs more useful and cost-effective." Specifically, the called for "a statement regarding to whom the Settlement applies; a program for transitioning customers to a price-responsive DR production; caps on the amount of reliability-triggered DR that qualifies for an RA payment; the details of a 'Wholesale Reliability Demand Response Product ' that the CAISO agrees to develop; and provisions relating to contingencies that arise from regulatory reviews." In May

2010, the Commission issued a Proposed Decision calling for the adoption of the settlement agreement.

Facilities that Only Fuel Electric Vehicles Are *Not* Utilities

The California Public Utilities Commission issued a Proposed Decision in May 2010 that would clarify that the people and facilities involved in the retail sale of electricity for the express purpose of fueling electric vehicles would not qualify as a utility. The ordering paragraph of the Proposed Decision reads:

> “The ownership or operation of a facility that sells electricity at retail to the public for use only as a motor vehicle fuel and the selling of electricity at retail from that facility to the public for use only as a motor vehicle fuel does not make the corporation or person a public utility within the meaning of Pub. Util. Code § 216 solely because of that sale, ownership or operation.”

LEGISLATIVE:

Smart Thermostat Legislation

In September 2008, Governor Schwarzenegger vetoed a bill that would have provided guidance for how the California Energy Commission (CEC) may or may not regulate deployment of programmable communicating thermostats. In particular, the legislation would have established the following:

> “The [California Energy] commission shall not adopt or approve a building standard that requires installation of a device that may be controlled remotely by any person or entity other than a building resident the utility customer, including, but not limited to, a programmable communicating thermostat equipped with a non-removable radio data system communications device that is compatible with the default statewide demand reduction communications system used by utilities to send price and emergency signals, unless all of the following conditions apply to the device:
>
> (a) The device shall be installed without default settings.
>
> (b) Only the resident utility customer may authorize remote control of the device by another person or entity.

(c) The resident utility customer retains the right to deny access to or to override a remotely controlled setpoint at any time."

The Senate passed the bill in May 2008, and the State Assembly modified and passed it in August 2008. The bill was introduced in February 2008.

Bill Prohibiting Default Time-Based Pricing Until 2013

In October 2009, Governor Schwarzenegger signed a bill that prohibits the California Public Utilities Commission from mandating time-based pricing or establishing it as the default option until at least January 2013. The law also bans mandatory or default real-time pricing until January 2020. It permits, however, the Commission to authorize utilities to offer customers time-based pricing and other demand response programs as opt-in opportunities. The new law also sets the conditions for the Commission's acceptance of a utility's default time-based pricing plan without bill protection subsequent to January 2014. For example, the Commission only could approve default time-based pricing if customers could opt-out without incurring a penalty. The legislation was introduced in February 2009. The State Assembly and Senate passed it in September 2009.

Smart Grid State Policy Law

In October 2009 Governor Schwarzenegger signed legislation setting a smart grid policy for the state. Specifically, the new law directs IOUs and municipal utilities to create smart grid deployment plans and to file them by July 2011 with the California Public Utilities Commission for approval. The Commission, meanwhile, is responsible for establishing by July 2010 the requirements for such deployment plans. Finally, the law mandates that the Commission, beginning in 2011, report annually to the Governor and the state legislature on the status of smart grid deployments and on the related costs and benefits to ratepayers.

California Assembly Considering Energy-Storage Portfolio Standard

In February 2010 legislation was introduced into the California State Assembly that would establish an energy-storage portfolio standard. The bill would mandate that, beginning January 2012, electrical corporations and municipal utilities implement a "five-year program to employ distributed thermal, mechanical, or electrochemical energy storage systems to maximize shifting of electricity use for air-conditioning and refrigeration from peak demand periods to off-peak periods." The intent of these programs would be to reduce "electricity demand during peak demand periods." The legislation, furthermore, would require utilities to show the

California Public Utilities Commission how they intend to meet their energy-storage portfolio obligation when filing their renewable energy procurement plan. In the same document, utilities also would file plans for the aforementioned five-year program.

In April 2010 the bill passed the Utilities & Commerce Committee and the Natural Resources Committee, but in the process several provisions were removed from it, including:

- Language that would have set a statewide mandate for utility procurement of energy storage (2.25% of peak by 2014 and 5% of peak by 2020). It has been replaced by a provision that would require the California Public Utilities Commission to adopt, for each investor-owned utility, "appropriate energy storage system procurement targets to be achieved by [each utility] by January 1, 2015, and a second target to be achieved by January 1, 2020." These targets would have to be reevaluated at least tri-annually. The provision would mandate the same requirements for the local governing board of each publically owned utility

- The provision allowing for civil penalties for non-complying utilities.

- The provision that the California Energy Commission would be directed to create a program for utilities to adopt for the purpose of reducing peak demand. The program would "use energy storage systems to achieve all feasible, cost-effective air-conditioning and refrigeration load shifting in new and existing facilities."

- The provision that the California Energy Commission include, beginning in November 2011, information about the energy-storage portfolio standard in its biannual integrated energy policy report.

In late April 2010 the bill was referred to the Appropriations Committee.

Colorado

REGULATORY:

<u>Smart Grid Security and Privacy</u>

In August 2009 the Colorado Public Utilities Commission opened a proceeding to investigate the "security and privacy concerns" of deploying smart grid technologies. As the Commission explained when opening the proceeding, "It is therefore our view that the very characteristics that make smart grid information valuable to edge services [such as demand response] and environmental efforts also may have serious implications for consumer privacy." The Commission held an "Information Meeting" about the proceeding in August 2009. Comments were filed in September 2009. In February 2010 the Commission again solicited comments. Comments were filed in March 2010. This proceeding is an outgrowth from a June workshop held through the Commission's proceeding on the DOE's smart grid grants funded under the American Recovery and Reinvestment Act 2009 (Docket 09M-395EG).

LEGISLATIVE:

No legislative policy activity during the review period was known to the reviewers.

Connecticut

REGULATORY:

No regulatory policy activity during the review period was known to the reviewers.

LEGISLATIVE:

<u>Load Management and Time-Differentiated Pricing Legislation</u>

In March 2010 a bill was introduced into the Connecticut General Assembly that would direct the Connecticut Department of Public Utility Control to investigate "peak load or time of day pricing." It also would establish a resource-procurement plan for utilities that would include load management and demand response. Highlights from it include:

- "The Connecticut Electric Authority shall oversee the implementation of the procurement plan approved by the Department of Public Utility Control. . . . The electric distribution companies shall implement the demand-side measures, including, but not limited to, energy efficiency, load management, demand response, combined heat and power facilities, distributed generation and other emerging energy technologies, specified in said procurement plan through the comprehensive conservation and load management plan prepared . . . for review by the Energy Conservation Management Board. The electric distribution companies shall submit proposals to appropriate regulatory agencies to address transmission and distribution upgrades as specified in said procurement plan."

- "The Department of Public Utility Control shall promptly undertake a separate, general investigation of, and shall hold at least one public hearing on new pricing principles and rate structures for electric companies and for gas companies to consider, without limitation, long run incremental cost of marginal cost pricing, peak load or time of day pricing and proposals for optimizing the utilization of energy and restraining its wasteful use and encouraging energy conservation, and any other matter with respect to pricing principles and rate structures as the department shall deem appropriate. The department shall determine whether existing or future rate structures place an undue burden upon those persons of poverty status and shall make such adjustment in the rate structure as is necessary or desirable to take account of their indigency."

Resource-Procurement Legislation

In March 2010 a bill was introduced into the Connecticut General Assembly that calls for a resource-procurement plan for utilities that would include load management and demand response. The bills say:

> "The Division of Electricity Policy and Procurement shall oversee the implementation of the procurement plan approved by the Public Utilities Control Authority pursuant to section 16a-3a. The electric distribution companies shall implement the demand-side measures, including, but not limited to, energy efficiency, load management, demand response, combined heat and power facilities, distributed generation and other emerging energy technologies, specified in said procurement plan through the comprehensive conservation and load management plan prepared pursuant to section 16-245m for review by the Energy Conservation Management Board. The electric distribution companies shall submit proposals to appropriate regulatory agencies to address transmission and distribution upgrades as specified in said procurement plan."

Delaware

REGULATORY:

No regulatory policy activity during the review period was known to the reviewers.

LEGISLATIVE:

<u>Energy Efficiency and Conservation Act of 2009</u>

In July 2009 Governor Markell signed legislation implementing an Energy Efficiency Resource Standard (EERS) with a peak-demand-reduction provision. According to the law, each "Affected Electric Energy Provider"—electric distribution companies, rural electric cooperatives, or municipal electric companies—must reduce electricity consumption and peak demand by 2% by 2011 and by 15% by 2015. In support of this standard, the Delaware Energy Office is to report each December, beginning in 2011, about statewide electricity consumption and peak demand. A workgroup is to be formed with the task of recommending how the EERS policy should be implemented. Workgroup recommendations are due by December 2010, including one for the determination of the "appropriate level of equivalency for electricity demand response and energy efficiency measures in achieving compliance with the Energy Savings goals of § 1502 of this chapter." Finally, the law says that when preparing integrated resource plans, utilities are to give preference to demand response and demand-side management strategies. The legislation was introduced into Delaware's General Assembly in June 2009.

District of Columbia

REGULATORY:

<u>PowerCentsDC</u>

PowerCentsDC, the smart meter pilot program for more than 800 customers in Washington, DC, concluded in October 2009. The program began in July 2008, operating through two summer seasons and one winter. It was sponsored by the Smart Meter Pilot Program, Inc. (SMPPI), a nonprofit organization consisting of the Consumer Utility Board, the DC Office of the People's Counsel, the District of

Columbia Public Service Commission, the International Brotherhood of Electrical Workers, and Pepco. SMPPI reports having "gathered sufficient information regarding customer response to residential smart pricing to serve as a guide to future program design." Since the pilot ended, SMPPI has focused on analyzing the data it gleaned from the program.

PowerCentsDC was born out of a proposal Pepco filed with the DC Public Service Commission in June 2006. (PowerCentsDC was called SmartPowerDC until the name changed via a July 2007 proposed compliance tariff.) In April 2008, Pepco and SMPPI filed an application for a revised tariff seeking revisions to hourly pricing, critical-peak pricing and critical rebate rates in effort to make sure "that the average residential customer will not pay more on the program's pricing plans than the average residential customer pays on the standard offer service ('SOS') pricing plan." In July 2008, the Commission issued an Order in which it approved the revised smart-meter tariff, enabling the pilot to begin. The pilot featured three pricing options: (1) Hourly Pricing; (2) Critical-Peak Pricing; or (3) Critical Peak Rebate. It aimed, in compliance with a January 2007 Order, to measure (1) customer reduction in electricity consumption during peak times; (2) customer changes in overall consumption; (3) customer satisfaction with different pricing options and technologies; (4) usefulness of the selected technologies; and (5) value of presenting additional pricing information to customers.

LEGISLATIVE:

AMI-Implementation & Cost-Recovery Legislation

In June 2009 Mayor Fenty signed legislation passed by the City Council that provides authority to the city's "electric company" (Pepco) to deploy AMI. The intent of the new law is to bolster Pepco's application for a DOE smart grid grant funded under the American Recovery and Reinvestment Act 2009. The law also reaffirms the DC Public Service Commission's oversight of the utility's planned AMI program, and it creates a regulatory asset.

Florida

REGULATORY:

No regulatory policy activity during the review period was known to the reviewers.

LEGISLATIVE:

In July 2008, Governor Crist signed legislation that sets policy to "reduce the need for new power plants by encouraging end-use efficiency, reducing peak demand, and using cost-effective alternatives." The law authorizes the Florida Public Service Commission to set renewable-energy and energy conservation goals. It also allows the Commission to "require each utility to develop plans and implement programs for increasing energy efficiency and conservation and demand-side renewable energy systems within its service area." Furthermore, the law encourages the use of "solar energy, renewable energy sources, highly efficient systems, cogeneration, and load-control systems."

Georgia

No legislative or regulatory policy activity during the review period was known to the reviewers.

Hawaii

No legislative or regulatory policy activity during the review period was known to the reviewers.

Idaho

No legislative or regulatory policy activity during the review period was known to the reviewers.

Illinois

REGULATORY:

Statewide Smart Grid Collaborative

The Statewide Smart Grid Collaborative, which was established through a September 2008 Order from the Illinois Commerce Commission, is working to "develop a strategic plan for Smart Grid deployment in Illinois" and is holding workshops to that end. The group's effort will culminate in a report to the Commission, due in October 2010, which will recommend smart grid policies. The Commission, in turn, will open a proceeding to consider the report and its implications for developing the smart grid in Illinois. The Commission's Electric Policy and Telecommunications Policy Committees reviewed the progress of the Statewide Smart Grid Collaborative at a meeting in April 2010

Illinois Smart Grid Initiative

In April 2009 the Illinois Smart Grid Initiative (ISGI), a year-long project launched in June 2008 by the Galvin Electricity Initiative, published a report summarizing its efforts and outlining policy recommendations. In particular, the ISGI made recommendations in six policies areas it identified as being the most important to developing the smart grid in Illinois. Accordingly, the ISGI called for the Illinois Commerce Commission and its Illinois Statewide Smart Grid Collaborative to consider the following as they investigate the smart grid:

1. Smart Grid Planning, Monitoring, and Evaluation

2. Evaluation of Smart Grid Investments from a Societal Perspective

3. Alternative Methods of Ratemaking for Smart Grid Investment

4. Non-Utility Investment in the Electric Grid

5. Modification of Default Service Pricing

6. Effect of Statutory Renewable Resource, Demand Response and Energy Efficiency Goals on Smart Grid Planning and Implementation

The report, furthermore, said that a "workable definition of 'smart grid' would have to begin not by defining 'smart grid' from an engineering perspective as a bundle of technologies, but as a new system with four major components." These components are “smart technologies,” “smart rates,” “smart consumers,” and “smart governance.”

Illinois Power Agency and Power Procurement Plan

In August 2009 the Illinois Power Agency—a state office responsible for buying power on behalf of Illinois’ electric utilities, which was created in 2008 in compliance with a 2007 state law (SB 1592)—filed its “Draft Power Procurement Plan” for Ameren and ComEd with the Illinois Commerce Commission. The draft plan called for two bidding processes to take place in 2010 that would set procurement agreements lasting through May 2015. One would seek proposals for generation and renewable-generation capacity, and the other would solicit demand response resources. In November 2009 the Commission issued a Proposed Order that would approve a modified Power Procurement Plan. In December 2009, the Commission adopted the modified plan.

LEGISLATIVE:

No legislative policy activity during the review period was known to the reviewers.

Indiana

REGULATORY:

DSM Proceeding

Since July 2004 the Indiana Utility Regulatory Commission has been conducting a proceeding to consider the effectiveness of DSM programs. In December 2009, the Commission issued an Order in which it set a statewide EEPS goal of 2% annual reduction of electricity use within ten years; established “initial DSM Core Programs that shall be offered by jurisdictional electric utilities” throughout the state; and required the formation of a DSM Coordination Committee that is to issue one RFP for an third-party administrator to manage the DSM Core Programs and another for an “evaluation administrator” who will conduct EM&V relative to the DSM programs. None of the DSM Core Programs are demand response or smart grid programs. The Order, furthermore, finds that the Commission has sufficiently examined smart meter issues and that “specific further action on these issues on a standalone basis is unnecessary.” In May 2009, the

Commission published its “Indiana Electric DSM Investigation: Phase II Report,” in which it supported “broader deployment of smart grid technologies and wider availability of dynamic rate designs that facilitate energy savings and demand reduction objectives.”

End-Use Customer Participation in MISO and PJM

In September 2008, the Indiana Utility Regulatory Commission initiated a proceeding to investigate end-use customer participation in the demand response programs of Midwest ISO and PJM. In October 2008 the Commission held a preliminary hearing and prehearing conference to set the proceeding’s schedule. Later in October 2008, the Commission issued an Order announcing the procedural schedule. In February 2009, the Commission issued another Order approving a motion prohibiting the participation of Indiana end-use customers in “RTO demand response programs until further order of the Commission, unless such end-use customer has filed a petition for and received, after hearing, an order of the Commission authorizing such participation.” In June 2009 parties to the proceeding filed Proposed Orders.

EISA 2007 Smart Grid PURPA Standards

In December 2009 the Indiana Utility Regulatory Commission issued an Order in which it decided not to adopt the two smart grid PURPA standards enacted by the Energy Policy Act (EISA) 2007. The Commission wrote that “it is not appropriate or necessary to implement” the Smart Grid Investment Standard and the Smart Grid Information Standard because state law provides it with sufficient authority to weigh smart grid issues. The Commission expressed preference for “flexibility” in its ability to conduct proceedings. It explained: “Thus, we find that Indiana's current statutory scheme provides the Commission with sufficient authority to consider Smart Grid investments without the need to formally adopt the federal standards contained within the EISA. Flexibility is needed in this context and any attempts to adopt ‘mandatory’ requirements might inhibit the optimal development and deployment of Smart Grid technology.”

Iowa

REGULATORY:

Iowa's 2008 Energy Plan

In December 2008, Iowa's Office of Energy Independence issued the state's 2008 energy-independence plan, "Charting Our Own Course: Today's Challenges, Tomorrow's Opportunities." While the plan only makes recommendations in the areas of energy efficiency, renewable energy, and biofuels, it does connect load management to "large-scale" wind energy resources.

LEGISLATIVE:

In January 2008, legislation was introduced into the Iowa General Assembly to establish an energy-efficiency portfolio standard and to provide for a load management analysis. In March 2008 the bill was reintroduced, and it passed in April 2008. The Governor signed it in May 2008. The ratified legislation establishes a "commission on energy efficiency standards and practices" that is to operate from July 2008 through June 2010. It is to make recommendations to the Governor and General Assembly by January 2011. For the commission's purposes, "energy efficiency programs" include "direct and indirect load control" and TOU rates.

Kansas

REGULATORY:

Kansas Energy Report

In January 2009 the Kansas Energy Council published its "Kansas Energy Report 2009." It predicts that over 20 years electricity demand is to grow annually at a rate of 1.5% to 2%. The report also recommends that the "State of Kansas should adopt a goal of increasing energy efficiency such that the rate of growth in electricity peak demand and total energy is 50% less than it would have been absent the energy efficiency initiative."

Efficiency Guidelines

In November 2008, the Kansas Corporation Commission issued a Final Order that established a "comprehensive energy efficiency framework." The Final Order contains language that implies that the Commission would accept demand response programs proposed by utilities as part of their larger efficiency efforts.

LEGISLATIVE:

No legislative policy activity during the review period was known to the reviewers.

Kentucky

REGULATORY:

Incentive for Energy Independence Act Proceeding

Per Kentucky's Incentive for Energy Independence Act 2007, the Kentucky Public Service Commission opened a proceeding in November 2007 to examine a series of existing laws related to its authority over public utilities with respect to four energy-regulation issues, including one that concerns "demand-management" and includes discussion of a "rebuttable presumption" in favor of demand resources over new generation. The Commission directed the state's six utilities to file by December 2007 information about their current DSM programs. Utilities also were directed to submit any internal reports on the potential of demand response in the state. A public hearing was held in April 2008, and comments about the proceeding were filed in May 2008. In July 2008, the Commission filed a report with the General Assembly and issued an Order closing the proceeding. The filing, "Electric Utility Regulation and Energy Policy in Kentucky: A Report to the Kentucky General Assembly Prepared Pursuant to Section 50 of the 2007 Energy Act," evaluates and responds to all 39 recommendations made during the course of the proceeding. Two recommendations promote peak-demand reduction, and one specifically supports demand response.

Kentucky Clean Energy Corps

Governor Beshear announced in February 2009 the launch of the Kentucky Clean Energy Corps, a pilot program to make energy-efficient improvements in the homes of 100 low- and moderate-income residents. The program is to make homes 20% to 30% more energy-efficient. Smart meters are one of the tools participants of the program will receive to achieve this goal.

Kentucky Smart Grid Grants

In January 2010 Kentucky Department for Energy Development and Independence (DEDI) began soliciting proposals for projects that deploy and demonstrate smart grid technologies. DEDI made $2.65 million available in grant funding to qualified Kentucky electric energy distributors. The grant money was appropriated by the American Recovery and Reinvestment Act and allocated by the Department of Energy. Guidelines indicated that grants were to support projects “with a minimum investment of $100,000” that do at least one of the following things:

- “Increase electric transmission and distribution efficiency”
- “Increase electric transmission and distribution reliability”
- “Enable energy consumers to monitor and control their energy consumption”
- “Integrate smart meters, appliances, and system controls that enable energy providers to reduce peak electricity demands and consumption”
- “Enable the control and monitoring of distributed, low-carbon electric generation”
- “Develop and implement rate structures that will encourage energy conservation and peak load shifting.”

Proposals were due in February 2010.

EISA 2007

In February 2010 the Kentucky Public Service Commission issued, as part of its EISA 2007 proceeding, a memorandum containing a document, “Commission Staff Smart Meter and Smart Grid Guidance,’’ that enumerates the key issues and questions that should be addressed in the proceeding. The Staff document was a response to a request from parties attending the proceeding’s October 2009 Informal Conference. Participating parties, according to the Commission, “expressed a willingness to work collaboratively but requested that Commission Staff provide guidance to the parties regarding issues it believed should be addressed.” Topics in the guidance document include smart grid definitions and benefits; technologies that drive smart grid adoption; cybersecurity; and consumer attitudes about demand response and energy-information displays. The Commission directed parties to the proceeding to file, by April 2010, “a report that identifies a schedule and describes a plan for addressing the issues in the guidance document.” The Commission began its EISA 2007 proceeding in November 2008.

LEGISLATIVE:

No legislative policy activity during the review period was known to the reviewers.

Louisiana

No legislative or regulatory policy activity during the review period was known to the reviewers.

Maine

REGULATORY:

No regulatory policy activity during the review period was known to the reviewers.

LEGISLATIVE:

Peak-Demand-Reduction Standard

In June 2009, Governor Baldacci signed legislation that set a peak-demand-reduction standard of cutting 100 MW of peak demand by 2020. According to the law, the Efficiency Maine Trust Board is tasked with creating triennial energy plans with "sustained energy efficiency" programs that are to meet several targets, including:

- "Reducing peak-load electric energy consumption by 100 megawatts by 2020"
- "By 2020, achieving electricity and natural gas savings of at least 30%. . . ."

The law does not mention demand response or name any programs to be responsible for reducing peak demand.

Upon completion, the triennial plan is to be reviewed and approved by the Maine Public Utilities Commission. After Commission approval, the Efficiency Maine Trust is to provide the plan to the state legislature, which may in turn introduce legislation to support aspects of the plan.

The new law also established the Commission to Study Energy Infrastructure, which is to "examine the feasibility and effects of the State entering into agreements for leasing or otherwise allowing the use of state-owned lands or assets, including . . . the installation of lines . . . or other structures for the transmission of energy resources, communication transmission systems or related facilities." While considering upgrades to the electricity transmission system, this Commission is to weigh whether a smart grid could "help the State achieve its energy goals."

<u>Smart Grid Policy</u>

In March 2010, Governor Baldacci signed legislation known as the "Act to Create a Smart Grid Policy in the State." In establishing the need for a statewide smart grid policy, the legislation's preamble notes the "cost of electricity to consumers" and the "consequences of climate change" before saying that it is "vital that a comprehensive smart grid policy be developed." The legislation continues to set policies for goals; resource assessments; a "smart grid coordinator"; a transition plan for displaced employees; cost recovery; reporting; and consumer education. The smart grid policy goals are:

- "Deployment and integration into the electric system of demand response technologies, demand-side resources and energy-efficiency resources"

- "Deployment of smart grid technologies, including real-time, automated, interactive technologies that optimize the physical operation of energy-consuming appliances and devices, for purposes of metering, communications concerning grid operation and status and distribution system operations"

- "Deployment and integration into the electric system of advanced electric storage and peak-reduction technologies, including plug-in electric and hybrid electric vehicles"

- "Provision to consumers of timely energy consumption information and control options"

- "Identification and elimination of barriers to adoption of smart grid functions and associated infrastructure, technology and applications."

Maryland

REGULATORY:

EmPOWER Maryland Act

In September 2008, Maryland utilities complied with the EmPOWER Maryland Energy Efficiency Act of 2008 by filing with the Maryland Public Service Commission "proposals for achieving the electricity savings and demand reduction targets specified" in the law. (EmPower Maryland mandates a 15% reduction in peak demand by 2015; in August 2008 the Commission posted utility-specific reduction targets on its website.) The Commission then opened a separate proceeding for each utility that filed a plan and decided to considering all five proceedings simultaneously.

In each of the proceedings, the Commission solicited comments and scheduled stakeholder meetings and hearings for October and November 2008. In December 2008 the Commission held a "consolidated legislative-style" hearing for the five proceedings.

In another December 2008 Order, the Commission directed its Staff to meet with the utilities in the five proceedings to prepare an RFP for a "baseline Maryland energy efficiency and conservation study" that would provide "a concrete foundation to judge the effectiveness of EE&C proposals." In February 2009, the Staff filed its draft RFP for a "Maryland Electric Energy Baseline Study" along with a report about its development. The Commission solicited comments about the draft RFP and the report. In April 2009 the Commission held a hearing to consider the draft RFP, the report, and the comments filed. In May 2009 the Commission issued an Order in which it approved the RFP and directed the five utilities to issue it. The Commission, furthermore, outlined the RFP process:

- The five EmPOWER Maryland utilities are responsible for facilitating, via the RFP, the process of procuring a vendor to conduct the baseline study
- Either the Commission or its Staff, though, will actually choose the vendor
- The chosen vendor "will take direction from" and provide its findings to either the Commission or its Staff
- The five utilities will pay the vendor for its work on the baseline study, though they "are authorized to recover the reasonable and necessary costs billed by the vendor for these services through their EmPOWER Maryland monthly surcharge."

The Commission, however, did not determine in the Order whether the baseline study will be market-specific or measure-specific and what information it should yield. The Commission plans to address these questions while it is selecting the vendor.

At the end of December 2008, the Commission issued Orders in all five proceedings in which it either approved or rejected aspects of the EE&C proposals filed. While the Commission called for revisions to certain aspects of the plans, it did not direct any of the utilities to revise their demand response proposals. Summaries of the Commission's decisions about the demand response provisions in each utility's plan are below:

Allegheny Power

The Commission noted that Allegheny Power (AP) has developed an "Advanced Utility Infrastructure (AUI) Pilot Project" that through which it would offer demand response and "smart grid technology" to 1,140 of its residential and commercial customers." It continued to say that AP did not include in its proposal any projected energy and or demand savings. AP, however, did report expected project costs between 2009 and 2011 to be $4.9 million. The Commission scheduled a hearing about the proposed AUI pilot for January 2009, but otherwise did not render a decision about the project. In May 2009 AP a revised proposal for the AUI pilot in which it proposed a 1,140-customer project to start in July 2009 and finish in November 2010. The proposal called for

- "Demand response based upon customer preferences, through the use of AMI meters and remote control of loads at customer sites"
- "Support of day-ahead and real-time priced rate structures"
- "System loss calculation using line monitoring devices"
- "A single, open, interoperable network infrastructure for intelligent communications and computational capacity."

AP predicted that the programs would reduce peak demand by 130 MW, cut energy consumption by 15 GWh, and save each customer $80 per year.

BG&E

The Commission said that it already has approved two demand response programs for BG&E and that, in addition, the utility is conducting a pilot program, Smart Energy Pricing. As a result, according to the Commission, BG&E already met the 15% peak-demand reduction goal and was exempt from proposing new demand response programs.

Pepco

In its filing, Pepco discussed three demand response programs, and the Commission responded separately to each:

(1) Residential Air Conditioner Direct Load Control Program: The Commission approved this program in April 2008 and therefore took no action on it in the December 2008 Order

(2) Non-Residential Air Conditioner Direct Load Control Program: Pepco has indicated that it will propose the actual parameters of this program for small, commercial, government and institutional customers when it knows when its AMI project will be complete; accordingly, the Commission took no action on it in the December 2008 Order

(3) Non-Residential Internet Platform Program: The Commission approved this program that will enable larger customers to "easily participate in the PJM demand response markets." The program, the Commission said, "will provide noticeable peak demand reductions, 11 MW for 2011, at a very modest annual cost of $407,000 for 2011." Furthermore, the Commission directed Pepco to report on "all DR bid into the PJM markets within 60 days of the bid so that the PJM DR revenue can be used to offset DSM charges to ratepayers."

Collectively, Pepco's proposed EE&C programs are to reduce 2011 peak demand by 509 MW (thereby achieving 174% of the EmPOWER Maryland peak-demand reduction goal for 2011) and 2015 peak demand by 780 MW (achieving 115% of the 2015 goal).

Delmarva Power & Light

In its filing, Delmarva Power & Light (DP&L) discussed three demand response programs, and the Commission responded separately to each:

(1) Residential Air Conditioner Direct Load Control Program: The Commission approved this program in April 2008 and therefore took no action on it in the December 2008 Order

(2) Non-Residential Air Conditioner Direct Load Control Program: DP&L has indicated that it will propose the actual parameters of this program for small, commercial, government and institutional customers when it knows when its AMI project will be complete; accordingly, the Commission took no action on it in the December 2008 Order

(3) Non-Residential Internet Platform Program: The Commission approved this program that will enable larger customers to "easily participate in the

PJM demand response markets." The program, the Commission said, "will provide noticeable peak demand reductions, 4.8 MW for 2011, at a very modest annual cost of $41,000 for 2011." Furthermore, the Commission directed DP&L to report on "all DR bid into the PJM markets within 60 days of the bid so that the PJM DR revenue can be used to offset DSM charges to ratepayers."

DP&L's proposed programs are to reduce 2011 peak demand by 91 MW (achieving 108% of the EmPOWER Maryland goal for 2011) and 2015 peak demand by 230 MW (achieving 102% of the EmPOWER Maryland goal for 2015).

Southern Maryland Electric Cooperative

In its filing, Southern Maryland Electric Cooperative (SMECO) discussed three demand response programs, and the Commission responded separately to each:

(1) Virtual Peaking Capacity Program with Smart Thermostat (aka "SMECO Cool Sentry"): The Commission approved this program in April 2008 and therefore took no action on it in the December 2008 Order. The program uses smart thermostats and AC-unit load-control switches and aims to reduce peak demand by 50 MWs in 2011 and by 75 MWs in 2018.

(2) Time- of-Use Rates: SMECO has indicated that it may later propose a TOU-pricing program. The utility's investigation of smart meters and AMI will inform its TOU-rate proposal if it develops one. The Commission took no action on this potential program in the December 2008 Order.

(3) Advanced Metering Initiative and Intelligent Grid: According to the Commission, SMECO is preparing a plan to deploy AMI "within the overall context of building an Intelligent or Smart Grid." The Commission took no action on this potential program in the December 2008 Order.

In all five Orders, the Commission deferred a decision about a "specific EM&V approach" and called for each utility to "apprise the Commission of its efforts to prepare for and participate in bidding of EE&C savings into the PJM capacity market, and the extent of EE&C savings . . . bid into each forthcoming capacity auction."

In the Orders, the Commission also called for a program to promote awareness among customers about energy efficiency and conservation opportunities that will be available as a result of these proceedings. Accordingly, the Commission convened a General Awareness Workgroup, which filed its proposed statewide education campaign in March 2009. The Commission held a hearing to consider it in

April 2009. In May 2009 the Commission issued an Order in which it approved the proposed campaign plan.

In February 2009 the Commission held meetings to discuss the enhancements utilities are to make to their EE&C plans and to discuss the implementation of the low-income and moderate-income programs of the utilities' EmPOWER Maryland plans. In March 2009 the utilities filed revisions to their EE&C programs in compliance with the Commission's December 2008 Order. In August 2009, the Commission issued Orders approving the revisions.

In March 2010, the Commission held a hearing to review the 2009 EmPOWER Maryland Annual Reports filed by the utilities.

Funding of Northeastern Energy Efficiency Partnership's (NEEP) Evaluation Monitoring and Verification Forum

In June 2009 the Maryland Public Service Commission held a hearing to consider whether it should direct the five utilities---Allegheny Power, Baltimore Gas & Electric, Pepco, Delmarva Power & Light, and Southern Maryland Electric Cooperative---beholden to the goals of the EmPOWER Maryland Energy Efficiency Act 2008 to fund "certain selected projects" of the Northeastern Energy Efficiency Partnership's (NEEP) Evaluation Monitoring and Verification Forum. The Commission questioned whether such funding "is a cost-effective means to facilitate the EmPower Maryland Utilities' development of EM&V measures for their EmPower Maryland programs that have been approved or will be approved by the Commission." In July 2009 the Commission issued an Order in which it directed the Maryland Energy Administration (MEA) to "take whatever actions are needed to obtain authority" to fund the utilities' participation in the NEEP EM&V Forum in 2009 and 2010. The Commission also directed the utilities to provide purchase orders to NEEP "to reflect a firm commitment to fund the identified EM&V Forum projects." These purchase orders were to be voided once MEA secures financial authorization for the EM&V Forum and submits its own purchase orders to NEEP.

EmPOWER Maryland Act Goals and Munis and Coops

In December 2009 the Staff of the Maryland Public Service Commission filed a legal memorandum arguing that municipal utilities and electric cooperatives that serve fewer than 250,000 people may undertake energy efficiency and conservation measures in compliance with the EmPower Maryland Act 2008 "without having to implement plans to achieve the per capita electricity consumption and peak load reduction targets" established by the law. The Staff also said that if the Commission decides that municipal and cooperative utilities do not have to file consumption- and peak-demand-reduction plans, then it may be necessary for the Commission to ask the investor-owned utilities that did file plans to make adjustments to them. The EmPower Maryland Act set goals of reducing per capita electricity consumption by 5% by 2011 and 10% by 2015 and of cutting per capita peak demand by 5% by 2011, 10% by 2013, and 15% by 2015. It directed the Commission to require each "electric company" to adopt plans to achieve these goals. It also said that municipal and cooperative utilities should "include energy efficiency and conservation measures as part of the service offered to their customers."

Long-Term Procurement, Demand Response, and Smart Grid

In July 2008, the Commission issued an Order in which it directed investor-owned utilities to file by October 2008 an "evaluation of a long-term procurement plan for providing SOS [standard offer service]" to residential and small commercial customers over a period up to fifteen years in length. The Commission, furthermore, provided parameters for creating the plan, directing IOUs to consider demand response and the smart grid as potential resources. The Commission held hearings about the plans filed in December 2008. The Commission opened this proceeding in August 2007—pursuant to Senate Bill 400, signed by Governor O'Malley in May 2007—in order to "examine various options" for providing standard offer service to residential and small commercial customers. Comments were filed in November 2008. In December 2008, reply comments were filed and the Commission held three hearings.

Gap RFP Proceeding

In August 2008 the Maryland Public Service Commission commenced a proceeding to investigate the possibility of having the state's IOUs issue "GAP" RFPs to secure additional resources to ensure reliability is not threatened if planned transmission-line projects fail to be realized in 2011 and 2012. The Commission received comments in September 2008 and held legislative-style hearings in October 2008. In November 2008 the Commission issued an Order in which it concluded that the Mid-Atlantic region faces a reliability gap of about 2,600 – 3,000 MW for 2011 – 2012. (Of the total gap predicted, 600 – 690 MW is attributable to Maryland.) Furthermore, the Commission not only determined that demand response and distributed generation should be the primary resources used to ensure reliability, but it also did the following:

- Directed Maryland's IOUs to draft GAP RFPs for resources that "meet the requirements of PJM's Emergency Load Response Program" and that would be in addition to the resources proposed by the IOUs in their EmPOWER Maryland Act filings.

- Directed its Staff to convene a Distributed Generation Working Group (DGWP) to determine the “scope of potentially available distributed generation resources” and to propose a way to “harness” those resources identified that do not participate in PJM's Emergency Load Response Program and that do not respond to the IOUs’ GAP RFPs.

The Commission held stakeholder meetings in December 2008 to review the proposed GAP RFPs IOUs filed. Later in December 2008, Commission Staff filed its report about the proposals, noting that the IOUs must issue their GAP RFPs in January 2009 in order to be able to bid resources obtained through them in PJM’s 2012 – 2013 RPM Auction. In response to the Staff’s report, the Commission issued a Notice of Expedited Procedural Schedule in which said comments about the report must be filed in January 2009 and through which it scheduled a hearing for January 2009.

In January 2009 the Commission issued an Order in which it adopted a slightly revised version of its Staff’s December 2008 recommendation. The Commission directed its Staff to modify the RFP template and set the timeline for IOUs to issue RFPs. The Commission also noted that it will address concerns about cost recovery “when and if” it approves any bids pursuant to the RFPs.

The Commission’s DGWG met twice in January 2009. At the meetings, the DGWG, which was tasked by the Commission to file a report by March 2009, discussed the scope of its own work relative to the GAP RFPs. It determined that it will not consider how much distributed generation should be included in the GAP RFPs but that it instead will focus on technical feasibility and economic assumptions that either foster or discourage the growth of distributed generation. It also addressed:

- The Commission Staff's Model Distributed Generation Tariff Outline
- Increased Awareness of and Participation by Emergency Generation Facilities
- Incentives
- Interconnection Agreements
- Standby Tariff/Regulations
- An incentive-proposal subgroup, which would be tasked with writing a strawman proposal.

In February 2009 the Commission held a hearing to consider whether to accept any of the bids filed in response to the GAP RFPs. In addition, the hearing featured PJM’s updated analysis of the state’s potential capacity gap.

In March 2009, the Commission issued an Order accepting bids made in response to the GAP RFPs issued by the state’s IOUs. In the Order the Commission adopted a recommendation, made by its Staff in comments filed in February 2009, to “execute demand response contracts" for about 400 MW of demand response. The IOUs may recover the costs of the bids, according to the Commission, "on a per kWh basis across all customer classes." In May 2009 the Staff filed a report with the Commission about the DGWG. In the report, the Staff suggests that "at least 400 MW of emergency generation that currently does not participate in PJM emergency demand response programs could potentially participate in those programs." Comments about the report were filed in June 2009. In July 2009, the Commission held a legislative-style hearing.

In March 2020 the Commission held a hearing to update the "the amount of capacity that is anticipated to be required in the years 2012-2016 to avoid any potential reliability problems in the State."

Maryland Energy Administration Smart Grid Project

In September 2008 the Maryland Energy Administration (MEA) received a $461,793 competitive grant from the US DOE for the development of a smart grid. With the funding, the MEA created the Smart Grid Maryland Project. The Smart Grid Maryland Project is engaged in five activities:

- *Review of Smart Grid Technologies and Programs*: "The project team has conducted an extensive literature review; research on Smart Grid activities at the state, regional, and national levels; a technology review; and a preliminary cost/benefit analysis of expected efficiency savings, reliability, and customer bill savings from Smart Grid programs."

- *Smart Grid Stakeholder Involvement*: "MEA is sponsoring two Smart Grid Stakeholder Meetings at Chesapeake College and the University of Maryland to inform Maryland consumers and key stakeholders on the project. A Smart Grid Forum is planned for the fall of this year where the results of the project will be shared."

- *Analysis and Order of Implementation for Smart Grid Elements*: "The project team will quantify the most effective mix of Smart Grid elements and Smart Grid alternatives for consumers and will rank them in terms of their cost-effectiveness and ease of implementation. Additionally, the project will also recommend an order of implementation for the recommended Smart Grid elements and alternatives."

- *Smart Grid System Design*: "Depending on the results of the previous tasks, MEA and the project team will identify and recommend specific components of a Smart Grid program that might have the potential for success in achieving a 5 GW reduction in peak demand and 10.5 GWh of electricity savings in Maryland by 2015, directly contributing to the achievement of the *EmPOWER Maryland* goals."

- *Regulatory Report*: "MEA and the project team will deliver a final summary report on the results of the previous four tasks, including the costs and benefits of Smart Grid deployment in Maryland. This report will be made available to the Governor, the Public Service Commission, and other key organizations and institutions in Maryland."

In June 2009 the MEA's Smart Grid Maryland released a report that evaluates technologies, policies, and regulatory issues. It also reviews literature about the smart grid as well as existing smart grid efforts.

LEGISLATIVE:

No legislative policy activity during the review period was known to the reviewers.

Massachusetts

REGULATORY:

Three-Year Efficiency Plans

In January 2010, the Massachusetts Department of Public Utilities (DPU) issued an Order in which it approved the three-year (2010 through 2012) energy-efficiency plans filed in October 2009 by electric distribution companies and municipal aggregators in compliance with the state's Green Communities Act 2008. The Green Communities Act allows the tri-annual efficiency plans to include demand response. None of the approved programs did.

Smart Grid Pilot Proposals in Compliance with Green Communities Act 2008

In April 2009 Massachusetts utilities filed proposals for smart grid pilot programs with the Massachusetts Department of Public Utilities. These filings were in compliance with the state's Green Communities Act 2008, which mandates that every electric distribution company in the state file such a plan. Each pilot is to include smart meters as well as time-based rates in effort to reduce peak demand by 5%. The Department of Public Utilities opened a separate proceeding for each utility. It is to issue a decision about the proposals by August 2010, while the state's Secretary of Energy and Environmental Affairs is to report to the legislature about of the results of the pilots by September 2012.

Efficiency Plan Filings in Response to Green Communities Act 2008

The Green Communities Act 2008 directs the state's "electric distribution companies and municipal aggregators with certified efficiency plans" to jointly file every three years an "electric efficiency investment plan" that may include demand response programs. In May 2009 a coalition of Massachusetts utilities filed a three-year efficiency plan (for 2010 – 2012) with the Commonwealth's Energy Efficiency Advisory Council, the group tasked by the Green Communities Act with reviewing the plan. In the plan, the coalition---consisting of NSTAR, National Grid, Western Massachusetts Electric, New England Gas, Unitil, Berkshire Gas, Bay State Gas, Blackstone Gas, and Cape Light Compact---proposed demand response programs for C&I customers. The plan did not project the possible MW savings of its programs, but it did include forecasts of energy and cost savings as well as emissions reductions for the period 2010 – 2012. In October 2009 the Council approved statewide savings targets and performance incentives. The utilities composing the coalition responded by designing and filing company-specific plans. The Department of Public Utilities then considered each plan separately.

LEGISLATIVE:

No legislative policy activity during the review period was known to the reviewers.

Michigan

No legislative or regulatory policy activity during the review period was known to the reviewers.

Minnesota

REGULATORY:

Minnesota Energy Office's Transmission Study

In September 2009 the Minnesota Office of Energy Security released, in compliance with the state's Next Generation Energy Initiative, a study describing how the state's transmission infrastructure would handle the addition of 600 MW of dispersed renewable generation. The report, "Dispersed Renewable Generation Transmission Study Phase II," concludes that "statewide dispersion of 600 MW of additional DRG is not possible without encountering significant limiters unless the system is upgraded." It also says that it is a "fundamental policy of the Minnesota Office of Energy Security" that it meets Governor Pawlenty's Next Generation Energy Initiative's renewable-energy and GHG-emission goals by not only increasing high-voltage transmission capacity but also by "using our existing transmission infrastructure more efficiently, through increased energy conservation and efficiency, demand response, emerging efficiency technologies and dispersed renewable generation where it can be interconnected reliably."

LEGISLATIVE:

No legislative policy activity during the review period was known to the reviewers.

Mississippi

No legislative or regulatory policy activity during the review period was known to the reviewers.

Missouri

No legislative or regulatory policy activity during the review period was known to the reviewers.

Montana

No legislative or regulatory policy activity during the review period was known to the reviewers.

Nebraska

No legislative or regulatory policy activity during the review period was known to the reviewers.

Nevada

REGULATORY:

No regulatory policy activity during the review period was known to the reviewers.

LEGISLATIVE:

Renewable and Energy Efficiency Portfolio Standard

Nevada originally created its energy efficiency and renewable energy portfolio standard via legislation in 1997. The Nevada Public Utilities Commission later added a peak-demand multiplier, which allows savings from efficiency measures that also reduce peak demand to receive twice the number of credits they would otherwise. In May 2009 Governor Gibbons signed legislation that expands the state's renewable energy and energy efficiency portfolio standard. Whereas the standard previously had a cap of 20%, the law changed it so that by 2025 electricity providers must generate electricity from renewable resources or reduce consumption through energy efficiency in an amount that equals 25% of the total electricity sold to retail customers that year.

New Hampshire

REGULATORY:

EPACT 2005

In September 2008, the New Hampshire Public Utilities Commission issued an "Order Concluding Investigation" in its proceeding to consider adopting PURPA Standard 14 ("Time-Based Metering and Communications") as enacted in EPACT 2005 in which it directed its Staff to create a working group to guide deployment of AMI and time-based rates. The Staff, furthermore, was to report to the Commission by December 2008 about the "next steps toward utility specific cost-benefit analyses regarding such implementation and related matters." In the report it filed, the Staff reviewed its investigation of utilities' work to deploy smart metering and time-based pricing.

In January 2008, the Commission concluded that it was "appropriate to implement" time-based metering standards, but that "the details, including cost-benefit analyses, form of rate design, time of implementation and applicable customer classes shall be determined in a separate proceeding or proceedings to be initiated by the Commission." The Commission said that it wanted to answer the question of which time-based rate is appropriate for each utility and customer class. As a result, it indicated that it planned to deal with every utility separately and not to open a broad rulemaking proceeding.

The Commission's first response to PURPA Standard 14 actually came in the form of a June 2007 Order adopting it. The Commission stayed this decision via an August 2007 Order, however, in response to a July 2007 Motion for Rehearing of Order, which argued that the Commission should have held a public hearing on EPACT 1252.

EISA 2007

In December 2008, the Staff of the New Hampshire Public Utilities Commission filed its finding that the Commission has no "further obligation" to investigate the four PURPA Standards—which address the smart grid—established by the Energy Independence and Security Act of 2007. As the Staff interpreted, EISA 2007 exempts a state regulatory commission from investigating the PURPA Standards if that state has already considered or is considering, through legislative or regulatory process, adoption of similar standards. The Staff explained that in its view the Commission's work in its EPACT 2005 Proceeding (Docket DE 06-61) qualifies as having considered comparable standards to the two smart grid standards set by EISA 2007:

> "Staff's ongoing Commission-directed investigation into smart grid investments constitutes an investigation into the consideration of a standard comparable to the second standard numbered 16, Smart Grid Investments. In addition, Staff believes the investigation also covers the second standard numbered 17, Smart Grid Information . . . .
>
> "Therefore, because the Commission is currently investigating a standard comparable to second standards numbered 16 and 17, in Staff's view, the Commission has no additional obligation to investigate Consideration of Smart Grid Investments and Smart Grid Information."

LEGISLATIVE:

No legislative policy activity during the review period was known to the reviewers.

New Jersey

REGULATORY:

<u>Energy Master Plan</u>

In October 2008 Governor Corzine released the New Jersey Energy Master Plan (EMP)—the first such plan in the state in 15 years. The thrust of the EMP is a series of "action steps and strategies" designed to achieve five goals. Demand response and smart metering are included in the action items for achieving three of the five goals:

> *Goal 1:* "Maximize the State's energy conservation and energy efficiency to achieve reductions in energy consumption of at least 20% by 2020."
>
> *Goal 2:* "Reduce peak demand for electricity by 5,700 MW by 2020." Of this amount, 900 MW should be reduced through "peak demand initiatives."
>
> - "Expand incentives for participation in regional demand response programs [i.e., programs administered by PJM]."

- “Involve electric utilities in developing and implementing demand response programs.”

- “Target all commercial and industrial customers with a peak demand of 500 kW or greater for reduction in peak demand and continue to develop incentives that achieve significant peak demand saving.”

- “Pilot different technologies [including smart meters and AMI] and rate structures for residential customers and customers with a demand of less than 500 kW.”

- “Monitor the results of all demand response initiatives through 2012 and implement the most effective mix of action steps to achieve a total peak demand reduction of 5,700 MW by 2020.”

Goal 3: “Strive to surpass the current Renewable Portfolio Standard goals with a new goal of achieving 30% of the State’s electricity needs from renewable sources by 2020.”

Goal 4: “Develop a 21st century energy infrastructure that supports the goals and action items of the Energy Master Plan, ensures the reliability of the system, and makes available additional tools to consumers to manage their energy consumption.”

- “Smart grid technologies will be considered within the broader context of this plan and their abilities to meet the goals and action items in this Energy Master Plan.”

Goal 5: “Invest in innovative clean-energy technologies and businesses to stimulate the industry’s growth in New Jersey.”

- “Establish the Energy Institute of New Jersey to support basic and applied energy research efforts at the colleges and universities in the State.” This institute is to coordinate with the State Energy Council and is to focus on developing these areas: Demand Response; Energy Efficiency; Advanced Meter and Advanced Grid Technologies; Renewable Energy; Energy Storage; Transmission and Distribution; and Plug-in Hybrid Electric Vehicles (PHEVs).

- “Meeting the Energy Master Plan’s aggressive targets for energy efficiency, renewable energy, demand response, and new generation will require tremendous growth in the ‘green collar’ jobs sector, from solar manufacturing and energy audits to HVAC installers and smart grid technology installations." It is therefore necessary to develop job-training programs to ensure green-collar job vacancies can be filled.

Furthermore, the EMP says that the state government should "lead by example." To that end, the EMP calls for the development of a demand response program for the state's facilities and agencies. Finally, the EMP advocates for working with PJM to "modify or replace the Reliability Pricing Model, with a mechanism that focuses incentives on new generation capacity, demand response, and energy efficiency."

Utility Infrastructure and Energy Efficiency Plans

In January and February 2009, New Jersey utilities filed proposals for energy-efficiency programs and for infrastructure upgrades in response to Governor Corzine's Economic Assistance and Recovery Plan, which called for such initiatives to stimulate the state's economy. Since then, the New Jersey Board of Public Utilities (BPU) has opened proceedings for each set of proposals.

LEGISLATIVE:

AMI Standard

In October 2008 the New Jersey State Assembly began considering legislation that would establish AMI standards in addition to standards for energy efficiency, renewable energy, and reducing GHG emissions. The bill, "An Act Concerning Advanced Metering Infrastructure Standards," passed the Telecommunications and Utilities Committee on in December 2008. An identical bill was introduced into the state Senate in June 2009. No further action was identified for this report.

Rules for Schools Contracting for Demand Response

Governor Corzine signed legislation in September 2008 that outlines how the state's boards of education and county colleges may contract for demand response and other services to conserve electricity.

Public Entities Must Consider Demand Response and Other "Energy Conservation Measures"

Governor Corzine signed legislation in January 2009 that encourages "public entities"—such as school districts, public colleges, and state, county, and municipal agencies—"to implement energy savings improvement programs." Demand response is one of the “energy conservation measures” New Jersey’s public entities may include in their energy-savings plan. Such plans shall, the law explains, “identify the eligibility for, and costs and revenues associated with the PJM Independent System Operator for demand response and curtailable service activities.” The new law allows public organizations to contract service providers for the performance of the energy conservation measures.

Smart Grid System Compatibility Act

In January 2010 a bill was introduced into the New Jersey Legislature on that would restrict utilities’ allowable cost recoveries to expenditures that complement smart grid goals. The legislation says:

> “An electric public utility shall not recover from ratepayers the costs of equipment or software unless the equipment and software is compatible with, and capable of interoperating with, a smart grid system.”

In March 2010 the bills was reported out of the General Assembly’s Telecommunications and Utilities Committee.

Smart Grid Pilot Program Act

In January 2010 a bill was introduced into the New Jersey Legislature on that would establish a pilot program involving 50,000 residences and would create a Smart Grid Technology Research Center at Rutgers University. Successful demonstration of the smart grid through the pilot would lead to the New Jersey Board of Public Utilities ordering the deployment of the smart grid throughout the state. The bill says:

- “The purpose and objectives of the pilot program and the research center shall be to attract additional federal funding to New Jersey for renewable energy research by providing a functional "smart grid" to serve as a platform for research on, and development and commercial deployment of, smart appliances, plug-in hybrid electric vehicles, electric distribution system automation equipment and other similar equipment or technology to improve the efficiency, reliability, and security of the electric power grid.”

- “The research center shall install a ‘smart grid’ system and conduct the pilot program within an area consisting of the Rutgers University Electrical and Computer Engineering building and other facilities located at the New

Brunswick campus of Rutgers, The State University and areas adjacent to the campus such that at least 50,000 residences are included."

- "Upon a demonstration of the cost effectiveness of 'smart grid' systems by the pilot program or by other efforts to implement such systems, including efforts in other states or internationally, the Board of Public Utilities shall order the deployment of 'smart grid' systems throughout New Jersey. The board is also authorized to remove regulatory barriers to 'smart grid' system deployment and to create by order or regulation such incentives as may be necessary to accelerate such deployment."

<u>AMI Standards</u>

In January 2010 a bill was introduced into the New Jersey Legislature that would direct the New Jersey Board of Public Utilities to set AMI standards. The bill says:

> The New Jersey Board of Public Utilities "shall initiate a proceeding and shall adopt, after notice, provision of opportunity for comment, and public hearing:
>
> (1) advanced metering infrastructure standards for customers of electric public utilities and electric power suppliers.
>
> The standards may require electric public utilities and electric power suppliers, as appropriate, to offer advanced or smart energy meters to any those industrial, large commercial, residential, and small commercial customers requesting such meters , as those customers are classified or defined by the board, regardless of the amount of electric power usage by such customers. The standards governing advanced or smart energy meters shall permit customers of electric public utilities and electric power suppliers who use such meters at their residences or places of business to receive real-time pricing and usage information on at least an hourly basis, and to adjust their usage during peak and off-peak hours to avoid higher prices that are charged for peak hourly usage; and. . . ."

New Mexico

REGULATORY:

Load Management

In January 2008, the New Mexico Public Regulation Commission opened a proceeding to investigate what effect incentives will have to motivate utilities to deploy energy efficiency and load management. In May 2008, the Commission held a "pre-workshop conference." Per a March 2009 Amended Notice of Proposed Rulemaking, comments and reply comments were filed in April 2009, and a hearing was held in May 2009. In April 2010 the Commission issued a Final Order in which it adopted a set of revised efficiency regulations, which address load management, and closed the proceeding.

Peak Reduction Targets in Energy Efficiency Strategy

In November 2008 New Mexico's Energy, Mineral, and Natural Resources Department released an energy-efficiency strategy for the state. The document, "New Mexico Energy Efficiency Strategy: Policy Options," addresses how the state can achieve the energy-efficiency goals set by Governor Richardson in 2007. (These goals are, relative to 2005 per-capita consumption, a 10% reduction in energy consumption by 2012 and a 20% reduction by 2020.) In particular, the strategy recommends that 25 major policies be implemented. Among these are policies for demand response, demand-side management, and decoupling:

Adopt Innovative Electricity Rates in Order to Stimulate Greater Electricity Conservation and Peak Demand Reduction

- "This policy would implement critical peak pricing or real-time pricing for residential customers in New Mexico with central air conditioning. A pilot program should first be conducted to determine the impacts and the cost effectiveness of different approaches."

- "Regarding critical peak pricing or real-time pricing along the lines implemented in California and Chicago, we assume such rate designs and associated enabling technologies result in 4 percent energy savings on average during the four summer months.... Given these assumptions, the estimated energy savings is 120 kWh per year per participating household on average. In addition to the energy savings, there should be a substantial reduction in peak power demand.

  "Assuming the number of households in the state grows to 825,000 by 2015, the aggregate electricity savings potential from residential demand response pricing is about 39 GWh/yr by 2015. By 2020, the savings potential could grow to an estimated 44 GWh/yr. These energy savings levels are very modest, about 0.5 percent of total projected electricity consumption by residential customers. However, the peak demand reduction potential could be much more significant, on the order of 200 – 400 MW by 2015. Once again, this assumes that all households with central air conditioning participate either voluntarily or due to a change in the basic residential tariff."

Expand Electric Utility Demand-Side Management Programs

- "Overall, this DSM effort would save about 12 percent of New Mexico's projected electricity use in 2020 in the absence of expanded DSM programs, and 15 percent of projected electricity use in the state in 2025."

- "With the assumptions explained above, the peak demand reductions reach 255 MW by 2012, 560 MW by 2015, 1,115 MW by 2020, and about 1,530 MW by 2025. . . . The peak demand reduction would be greater than the reduction in energy use in percentage terms, thereby helping utilities increase their average system load factor."

Adopt Decoupling and/or Shareholder Incentives to Stimulate Greater Utility Support for Energy Efficiency Improvements

- "Adopting decoupling and/or shareholder incentives would support the expansion of DSM programs in New Mexico . . . . But it is difficult to estimate what impact adopting decoupling or shareholder incentives alone would have on either DSM funding or energy savings. Furthermore, it would be unreasonable (double counting) to add savings from this policy to those attributed to Option 1 [Expand Electric Utility Demand-Side Management Programs]. Therefore we consider this option as helping to facilitate the savings attributed to Option 1, but not providing additional savings."

LEGISLATIVE:

No legislative policy activity during the review period was known to the reviewers.

New York

REGULATORY:

AMI

In August 2006 the New York Public Service Commission began a proceeding dedicated to AMI in response to its consideration of adopting PURPA Standard 14 (“Time-Based Metering and Communications”) as enacted in EPACT 2005. Through the proceeding, the Commission directed utilities to file AMI plans by February 2007. In February 2009, the Commission transferred this proceeding into a new AMI proceeding. A February 2009 Order in the new proceeding established minimum functional requirements for AMI systems and initiated a process for developing a “generic approach” to a cost-benefit analysis of AMI. The Commission set specific requirements, reversing a previous policy of establishing broad requirements, in effort to guide utilities as they develop AMI plans. The Commission noted, however, that AMI technologies “undoubtedly” will evolve, that it expects to be flexible with utilities as they try to meet the requirements, and that it may hold future proceedings to reset the requirements. The Order, furthermore, directed Con Edison, Orange & Rockland, and Central Hudson Gas & Electric---which had filed AMI proposals in the previous proceedings---to file “updated pilot AMI projects within 60 days.” In June 2009 a technical conference was held and comments were filed about developing a “generic benefit-cost approach for evaluating AMI.” In July 2009, the Commission issued an Order in which it approved proposals for projects developed by utilities in application for DOE smart grid grants funded under the American Recovery and Reinvestment Act 2009. The Order also authorized cost recovery for these projects.

State Energy Plan

New York’s first State Energy Plan in since 2003 was released in December 2009. It outlines how the state, over the next ten years, will maintain energy reliability “in a cost-effective and sustainable manner.” In so doing, it establishes energy-policy objectives for state agencies, and it sets strategies and offers recommendations for achieving those objectives. The plan proposes five overarching policy objectives:

- “Assure that New York has reliable energy and transportation systems”

- “Support energy and transportation systems that enable the State to significantly reduce greenhouse gas (GHG) emissions, both to do the State’s part in responding to the dangers posed by climate change and to position the State to compete in a national and global carbon-constrained economy”

- “Address affordability concerns of residents and businesses caused by rising energy bills, and improve the State’s economic competitiveness”

- “Reduce health and environmental risks associated with the production and use of energy across all sectors”

- “Improve the State’s energy independence and fuel diversity by developing in-state energy supply resources.”

It also proposes five strategies for meeting those objects as well as multiple recommendations for realizing each strategy. Demand response, smart metering, and the smart grid are fostered by some of the recommendations:

Strategy 1: Produce, Deliver and Use Energy More Efficiently

Strategy 2: Support Development of In-State Energy Supplies

Strategy 3: Invest in Energy and Transportation Infrastructure

Strategy 4: Stimulate Innovation in the Clean Energy Economy

Strategy 5: Engage Others in Achieving the State’s Policy Objectives

Governor Patterson announced the beginning of the process to create a new State Energy Plan in April 2008. Governor Patterson also created the State Energy Planning Board, which was in charge of the development process.

“45 by 15” Clean Energy Standard

During his State of the State Address in January 2009, Governor Paterson set a “45 by 15” goal for “clean energy.” He also proposed the creation of a research consortium on energy storage technologies that is to “make strides” in developing plug-in hybrid electric vehicle technology. These initiatives are part of his larger plan to “confront the current fiscal crisis head on.” The “45 by 15” standard is to create 50,000 new jobs. It is split between renewable energy and energy efficiency: by 2015 renewable energy is to meet 30% of the state’s electricity demand and efficiency is to meet 15% of it.

Reliability Projects Policy

In February 2009 the New York Public Service Commission issued an Order in which it adopted policies to guide “the regulated reliability backstop project review and implementation process." The Commission began this proceeding in December 2007 to establish guidelines for electricity infrastructure planning. In November 2008, and in compliance with the Order initiating this proceeding, the parties to the proceeding filed a report addressing the process for selecting reliability backstop projects, public-policy matters (e.g., objectives, long-term contracts, and potential impacts on competitive market), and permitting issues. Through its February 2009 Order, the Commission adopted the report's procedural recommendations for reviewing and implementing "backstop" projects. While the Commission did not discuss demand response at length, it did support the use of long-term contracts and note that such contracts enable the deployment of demand response. In June 2009 the Commission adopted a revised policy, one that takes into account "the cost allocation methodology that was approved by FERC."

DOE Smart Grid Grants Proceeding

In April 2009 the New York Public Service Commission began a proceeding to review smart grid proposals filed by six utilities that intended to apply for a DOE smart grid grant funded under the American Recovery and Reinvestment Act of 2009. In June 2009 the Commission held a Technical Conference about the smart grid in order to develop "a base of knowledge related to utility smart grid technologies in New York to assist in its decision making in determining whether to support investment in smart grid technologies." In July, the Commission approved the utilities' proposals, provided that they receive DOE funding.

New York Smart Grid Consortium

Governor David Paterson launched the New York State Smart Grid Consortium in August 2009. The Smart Grid Consortium was designed to "foster the development and deployment" of the smart grid by setting a "strategic vision on how best to deploy secure, efficient and reliable smart grid technologies in New York." It is composed of representatives from government agencies, utilities, and universities. Electricity customers also participate in the group's activities. In October 2009 the Smart Grid Consortium published its vision for the smart grid in New York. The October 2009 paper, "Strategic Smart Grid Vision and Technical Plan Report," was written to provide "an overview of the smart grid vision for New York State"; to describe "how all of NY's stimulus proposals submitted under the Department of Energy's (DOE) smart grid funding solicitations complement one another and map to a common vision"; and to outline "a strategy for the long-term engagement of the Consortium and the phased implementation of a comprehensive smart grid system."

LEGISLATIVE:

Legislation Banning Market Clearing Prices in Wholesale Auctions

In January 2009, the New York State Assembly began considering a bill that would prohibit NYISO from using market clearing prices in its auctions. NYISO's wholesale auctions, according to the legislation, would operate in a descending-clock format. The bill also would require the New York Public Service Commission to review electricity rates every three years; to "exercise its fullest jurisdiction over the ISO"; to forego its authority to mandate divestments of generating facilities; and to develop codes of conduct governing utilities. Interestingly, the bill notes that such codes of conduct are not to prevent utilities from "offering metering options to their customers." In January 2010 the legislation was referred to the Assembly's Corporations, Authorities and Commissions Committee.

North Carolina

REGULATORY:

REPS

In October 2009, the North Carolina Utilities Commission released its "2009 Annual Report—Renewable Energy & Energy Efficiency Portfolio Standard (REPS) in NC" and published its "Biennial Report Regarding Proceedings for Electric Utilities Involving Energy Efficiency and Demand-Side Management Programs, Cost-Recovery and Incentives." In January 2010 the Commission solicited comments about new rules "to establish requirements for participating in and paying for" a Renewable Energy Tracking System. Comments were filed in February 2010.

These developments are related to the state's renewable energy and energy efficiency portfolio standard (REPS), which was mandated by a law signed in August 2007—Senate Bill 3/Session Law 2007-397—and which was put into effect via a February 2008 Final Rule. Demand response is an eligible for cooperative and municipal utilities to use to meet the REPS

EISA 2007 PURPA Standards

In December 2009 the North Carolina Utilities Commission declined to adopt the four PURPA standards established by the Energy Independence and Security Act

(EISA) 2007. Two of the PURPA Standards were for the smart grid: the Smart Grid Investment Standard and the Smart Grid Information Standard. The Commission determined, however, that it will "open a separate docket in which it shall propose an addition to Commission Rule R8-60 regarding filing of smart grid technology plans by investor-owned utilities in IRP proceedings and schedule smart grid presentations by the State's investor-owned electric utilities." As previously reported, the Commission began this proceeding in November 2008 and in July 2009 the Commission's Staff filed its Proposed Order recommending that the Commission decline to adopt the four PURPA standards.

Smart Grid IRP Rule Amendment

In December 2009 the North Carolina Utilities Commission opened a proceeding to consider a possible mandate that utilities file "smart grid technology plans" as part of their integrated resource plans. This proceeding stems from the Commission's EISA 2007 proceeding, in which it declined, via a December 2009 Order, to adopt the two smart grid PURPA standards established by the federal law (Docket E-100, Sub 123). In that Order, the Commission determined that it would "open a separate docket in which it shall propose an addition to Commission Rule R8-60 regarding filing of smart grid technology plans by investor-owned utilities in IRP [integrated resource plan] proceedings and schedule smart grid presentations by the State's investor-owned electric utilities." The initiating Order of the new proceeding laid out this proposed revision, solicited comments, and directed IOUs to present "information regarding their smart grid technology plans" in January 2010.

Duke Energy Carolinas and Dominion North Carolina Power filed joint comments in February 2010 in which they write that they "agree that the potential impact of utilities' Smart Grid plans should be incorporated into the IRP process and reflected in the IRPs filed with the Commission . . . [but that the Commission's proposed amendment] requires a level of detail as to Smart Grid deployment that is inconsistent with the level of detail required for other planned and existing resources." As a result, Duke and Dominion included their own Proposed Amendment in their joint comments. One major difference between the two proposals is that the Commission's would require disclosure of intended activities while the utilities' would require retroactive reporting of results. The Commission sought comments, which were filed in March 2010.

LEGISLATIVE:

No legislative policy activity during the review period was known to the reviewers.

North Dakota

No legislative or regulatory policy activity during the review period was known to the reviewers.

Ohio

REGULATORY:

Peak-Demand-Reduction Plan in Compliance with State Law

In December 2009 three subsidiaries of FirstEnergy---Ohio Edison, Cleveland Electric Illuminating Company, and Toledo Edison---jointly filed with the Ohio Public Utilities Commission their Energy Efficiency and Peak Demand Reduction Program Portfolio for 2010 through 2012, thereby complying with Ohio law passed in May 2008 (Senate Bill 221). The portfolio includes two demand response programs: Interruptible Rate Tariff for C&I Customers and Direct Load Control Thermostat Program. The law mandating the filing sets a peak-demand-reduction standard: "Beginning in 2009, an electric distribution utility shall implement peak demand reduction programs designed to achieve a one per cent reduction in peak demand in 2009 and an additional seventy-five hundredths of one per cent reduction each year through 2018."

LEGISLATIVE:

Peak-Demand-Reduction Standard Modification

In May 2010 the Ohio Senate passed legislation that amends the tax code relative to energy efficiency and renewable energy projects. The bill, however, also modifies Ohio's energy-efficiency and peak-demand-reduction standards, which were established by a law signed in May 2008 (Senate Bill 221). The standards are that efficiency programs must yield by the end of 2025 energy savings greater than 22% and that peak-demand-reduction programs must reduce peak demand by 1% in 2009 and an additional 0.75% each year thereafter through 2018. The legislation's modifications to the standards are:

- “The bill permits an electric distribution utility to count toward meeting the benchmarks any energy efficiency savings or any reduction in demand that is produced by projects utilizing alternative energy technologies or energy efficiency technologies, products and activities that are located in its certified territory and for which an alternative energy revolving loan has been made. The bill also allows a mercantile customer that realizes energy efficiency savings or reduction in demand produced from these technologies, products, or activities that it owns and through which an alternative energy revolving loan has been made to elect to commit to the electric distribution utility the savings or reduction.”

- “Similarly, the bill permits an electric distribution utility to count toward meeting the benchmarks any energy efficiency savings or any reduction in demand that is produced by a special energy improvement project located in its certified territory. The bill allows a mercantile customer that realizes energy efficiency savings or reduction in demand produced by a special energy improvement project that it owns to elect to commit the savings or reduction to the electric distribution utility.”

As established by the legislation, an "alternative energy resource" is an “advanced energy resource” or a “renewable energy resource,” which include, respectively:

- “Demand-side management and any energy efficiency improvement”

- A “storage facility that will promote the better utilization of a renewable energy resource that primarily generates off peak”

The bill was introduced in the Senate in February 2010. The Ohio House of Representatives began considering it following its passage in the Senate.

Oklahoma

REGULATORY:

<u>Demand-Program Rules</u>

In October 2007 the Oklahoma Corporation Commission issued a Notice of Proposed Rulemaking to amend the Oklahoma Administrative Code by adding a subchapter, “Demand Programs,” that would establish rules for utilities deploying energy efficiency and demand response programs. In September 2008 the

Commission issued a revised set of proposed rules after receiving comments about its initial set of proposed rules. In November 2008, the Commission adopted the proposed rules before sending them, in December 2008, to Governor Henry and the state legislature for final approval.

The adopted rules stipulate:

- "As a part of the hearing process for approval of a utility's energy efficiency and demand response programs, the Commission shall set specific savings goals for each utility to reduce the rate of growth of peak demand, energy usage, and capacity addition without adversely affecting customer comfort or state economic activity, based on market potential studies, integrated resource plans, or other evidence."

- "All electric utilities under rate regulation of the Commission shall propose, at least once every three years, and be responsible for the administration and implementation of a demand portfolio of energy efficiency and demand response programs within their service territories. Such proposals shall be made by filing an application with the Commission on or before July 1 prior to the year the programs will be effective."

- Applications shall contain

    - "A base line describing the state of the market that each program is intended to address, taking into account applicable building energy codes and appliance and equipment energy standards"

    - "A description of the barriers to investment in energy efficiency and demand response in the absence of each program and the ways each program will reduce or eliminate these barriers"

    - "A plan for evaluation, measurement, and verification of performance and results of the demand portfolio and each program, including a plan for the use of deemed savings, if applicable, or the use of statistical sampling, if applicable, or the use of metering, where appropriate"

    - "A plan for evaluation of the market effects of each program or applicable group of programs"

    - "An estimate of expected savings in peak demand, energy use, and capacity, with location information about the source of savings if savings are not expected to be evenly distributed throughout the utility system"

- “Detailed explanation of the utility's request for recovery of prudently incurred program costs, recoupment of lost net revenue, and additional incentives the utility proposes it requires to make the programs workable”

- Demand portfolios are to do the following:
  - “Contain programs for all customer sectors”
  - “Strike a balance among procuring peak demand reduction, procuring energy savings, procuring capacity savings, educating the public, and transforming markets for energy efficiency”
  - “Promote comprehensive energy efficiency and demand response in buildings”

- Demand portfolios may do the following:
  - “Integrate energy efficiency and demand response”
  - “Include research and development that would lead to effective energy efficiency or demand response programs…so long as the total budget for such programs does not exceed five percent of the total budget for energy efficiency and demand response programs and the Commission finds the cost-effectiveness for the demand portfolio remains sufficient”
  - “Allow utility cooperation in state, regional and national programs that have the potential to save energy, reduce peak demand, or avoid capacity addition in Oklahoma”

- “Utilities are responsible for timely evaluation, measurement, and verification of their energy efficiency and demand response programs”

- “Each utility shall report by June 1 of each year on the performance of energy efficiency and demand response programs for the preceding program year and cumulative program performance.”

LEGISLATIVE:

<u>Legislation Creating RES with a Demand Response Provision</u>

In May 2010 Governor Henry signed the Oklahoma Energy Security Act, legislation that sets a Renewable Energy Standard for the state of 15% by 2015.

Utilities may use energy efficiency and demand-side management, including demand response, to meet the goal. Specifically, the new law states:

> "Energy efficiency and demand side management are important components to maximizing the energy resources of our state. Therefore, every electricity generating entity in Oklahoma may use energy efficiency and demand side management measures to assist the state in meeting its renewable energy standard. Provided, however, that demand side management may not be used to meet more than twenty-five percent (25%) of the overall fifteen percent (15%) renewable energy standard for the state. Energy conservation measures shall be described and quantified to the Corporation Commission on March 1 annually. The Commission shall make the final determination of the amount of generation capacity the electricity generating entity conserved and determine to what degree that will count toward meeting the renewable energy standard for the state."

Demand-side management is defined by the law as to include "load management or demand resource technologies, management practices or other strategies in residential, commercial, industrial, institutional or government customers that shift electric loads from periods of higher demand to periods of lower demand."

Oregon

No legislative or regulatory policy activity during the review period was known to the reviewers.

Pennsylvania

REGULATORY:

Alternative Energy Portfolio Standards

In 2006, the Commission established a proceeding to implement the Alternative Energy Portfolio Standards Act of 2004, but never issued a final ruling in it because the General Assembly began considering amendments to the law. In

September 2007, after these amendments were ratified—in Act 35 of 2007—and the Commission was obligated to solicit comments and craft final standards, the Commission reopened the public comment period in the proceeding. In September 2008 the Commission adopted final regulations for Alternative Energy Portfolio Standards, which don't "demand response" but "demand side management."

Implementation of Act 129

In response to Pennsylvania Act 129's ratification in October 2008, the Pennsylvania Public Utility Commission announced that it would implement in several phases the aspects of the new law that fall under its purview. (The intent of the law is to reduce energy consumption and demand; to enhance default service procurement; and to expand alternative energy sources.)

The first phase dealt with the Commission's obligation to adopt an energy efficiency and conservation program by January 15, 2009. In November 2008 the Commission Staff issued a draft proposal for an EE&C program. Comments were filed in response, and the Commission held a working group meeting in December 2008 to review the Staff's proposal and the comments filed in response to it. In November 2008 the Commission also held an en banc hearing to "seek information from experts on alternative energy resources, as well as energy conservation and efficiency, and demand side response (DSR) tools and programs to assist consumers." In January 2009 the Commission approved a Motion to establish an EE&C program. Specifically, the Motion directed EDCs to file EE&C plans by July 2009. Furthermore, it set standards for "measurement of annual consumption and peak demand reductions." In February 2009 EDCs filed their consumption forecast for the period between June 2009 and May 2010 and their hourly peak-load data for the period between June 2007 and May 2008. The EDCs filed their EE&C plans in July 2009, and the Commission responded by announcing that it would consider each plan through a separate proceeding.

Phase 2 of the Act 129 Implementation Plan began in November 2008 when the Commission issued a Secretarial Letter and requested comments on the "experience and qualification requirements the Commission must establish for conservation service providers." Act 129 stipulates that each EDC's EE&C filed with the Commission is to include a "contract with one or more" conservation service provider for the implementation of the plan. Furthermore, the law directs the Commission to create, by March 2009, "a registry of approved persons qualified to provide conservation services to all classes of customers." In February 2009, the Commission issued an Order in which it established a Conservation Service Provider Registry. The Commission also determined that its Bureau of Fixed Utility Services will manage the registry; adopted an application form for prospective conservation service providers; and set the “minimum experience and qualification requirements” applicants must meet to be included in the registry.

Phase 3 began in March 2009 when the Commission circulated and sought comments about its Staff’s draft standards for EDCs’ smart meter procurement and installation plans. In June 2009, the Commission issued an Implementation Order through which it adopted a set of “smart meter technology procurement standards” for EDCs to use as they develop their procurement and installation plans. The Order established “minimum smart meter capabilities” that go beyond those defined in Act 129 and provides guidance on smart meter deployments. To ensure that smart meter projects are cost-effective, the Commission required EDCs to also file “cost data” by August 2009. To facilitate both filings, the Commission held a stakeholder meeting in July 2009 to discuss the filing of plans and cost data. The EDCS filed the plans in August 2009, and the Commission considered each one in a separate proceeding. In April 2010, the Commission approved the “smart meter technology procurement and installation” plans filed by PPL, Met-Ed, Penelec, Penn Power, and Duquesne Light.

Technical Reference Manual for Assessing EE & DR Energy Savings

In May 2009 the Pennsylvania Public Utility Commission approved an updated Technical Reference Manual (TRM) for assessing "energy savings attributable to energy efficiency and demand response measures" taken by electric distribution companies in compliance with the state's Alternative Energy Portfolio Standards Act (AEPS) and Act 129 of 2008. In January 2010, the Commission issued a Tentative Order to realize the annual update of the TRM per its May 2009 Order. One of the “major goals” of the proposed modifications is to “provide reasonable methods for measurement and verification of the incremental energy savings without unduly burdening program or evaluation staff.” The Commission solicited comments and reply comments, due, respectively, 20 and 35 days “from the date of publication of the notice in the Pennsylvania Bulletin.” Pennsylvania Act 129 mandates the reduction of energy consumption by 3% and peak demand by 4.5% by 2013, while the AEPS requires the Commission to set standards for "tracking and verifying savings from energy efficiency, load management and demand side management."

Special Hearings on Wholesale Markets

In October, November, and December 2008, the Pennsylvania Public Utility Commission held three public en banc hearings to review the current state of and the potential for the wholesale electricity market. Comments and reply comments were filed in January 2009.

LEGISLATIVE:

No legislative policy activity during the review period was known to the reviewers.

Rhode Island

No legislative or regulatory policy activity during the review period was known to the reviewers.

South Carolina

No legislative or regulatory policy activity during the review period was known to the reviewers.

South Dakota

No legislative or regulatory policy activity during the review period was known to the reviewers.

Tennessee

No legislative or regulatory policy activity during the review period was known to the reviewers.

Tennessee Valley Authority

REGULATORY:

EISA 2007 PURPA Standards

In November 2009, the Tennessee Valley Authority (TVA) made its determinations on the four PURPA standards established by the Energy Independence and Security Act (EISA) 2007. TVA revised and adopted the two smart grid standards and adopted outright the standards for integrated resource planning and rate-design modification to promote energy-efficiency investments. The revised smart grid standards are “Standard 18: Smart Grid Investments” and “Standard 19: Smart Grid Information.” TVA began its consideration of the PURPA standards in December 2008. In July 2009, the TVA’s Staff published its report on and recommendations about the four standards.

Texas

REGULATORY:

Retail and Wholesale Markets and Smart Metering

In 2007 the Public Utility Commission of Texas began considering changes in retail and wholesale markets due to smart metering. The Commission divided the work of this proceeding between six projects: (1) Interim Project; (2) Web Portal Project; (3) ERCOT Settlement Project; (4) Home Area Network Project (HAN); (5) Retail Market Interface Project; and (6) Customer Education Project. In April 2008, the Commission Staff filed a memo summarizing the progress of the proceeding and the proceeding’s working group, called the Advanced Metering Implementation Team (AMIT). At the time of the memo, the AMIT was “finalizing the initial draft of requirements for the Transmission and Distribution Utility (TDU) web portal(s),” which are to provide at least “hourly data on a day-after basis” and possibly fifteen-minute data. The AMIT also was working on ERCOT settlement requirements. Furthermore, the April 2008 Staff memo reported that ERCOT had decided to “fund a study which would show the best way for ERCOT to change its systems to accommodate full settlement using 15-minute interval data from AMS, as meters are deployed.” In May 2009 the Commission held an AMIT workshop. In January 2010, the Commission held a workshop to discuss federal smart grid policies, which featured a presentation about NIST's smart grid interoperability standards.

Texas Web Portal with 15-Minute Consumption Feedback

In March 2010 the Public Utility Commission of Texas and a coalition of utilities launched the Smart Meter Texas website. Smart Meter Texas is a web portal through which customers with smart meters can track their electricity consumption in 15-minute intervals. The portal also will enable communication with Home Area Network (HAN) devices and will facilitate utilities' demand response offerings, such as pricing programs and direct load control. The Commission mandated the creation of the portal via a May 2007 Order.

Commission Reports that State Could Reduce Peak Demand by 23%

In December 2008 the Public Utility Commission of Texas released a study concluding that the state could reduce peak demand by 23.3% (or by more than 15,000 MW) over seven years. Furthermore, the report, "Study of the Potential for Energy Efficiency Measures under PURA 39.905," notes that there is "a significant amount of untapped technical and economic potential to reduce electricity use," including smart meters. The Commission undertook the study in compliance with the Texas Legislature, which, in 2007, asked it to consider whether it would be possible to cost-effectively meet efficiency goals of 30% by 2010 and 50% by 2015.

Smart Meter Evaluation

In March 2010 the Public Utility Commission of Texas set the parameters for the independent testing of smart meters, which it had decided was necessary following customers' reports of higher electric bills with smart metering. In an April 2010, the Commission said the independent review would include:

- "Testing and evaluating installed smart meters, individually and side-by-side"
- "Reviewing historic customer usage"
- "Analyzing customer complaints"
- "Evaluating utility smart meter processes, procedures and controls involving system hardware and software"
- "Tracking the accuracy of information transmitted from a smart meter to its final destination"
- "Sampling customer usage without smart meters to compare information and identify any inconsistencies with customer accounts that have smart meters."

The Commission contracted a consulting firm in March 2010 to conduct the evaluation. The consultant will test about 5,000 smart meters deployed by Oncor, CenterPoint, AEP Texas Central, and AEP Texas North. The consultant is to report its findings to the Commission by June 2010.

LEGISLATIVE:

No legislative policy activity during the review period was known to the reviewers.

Utah

REGULATORY:

No regulatory policy activity during the review period was known to the reviewers.

LEGISLATIVE:

Direct Load Control Legislation

In March 2010 Governor Herbert vetoed a bill that would have set a state policy "to encourage reasonable demand side management and direct load control programs." The bill included a clause that would have directed the Utah Public Service Commission to approve direct load control programs if they passed a cost-benefit test and provided an opt-out provision. The Utah Senate passed the legislation in March 2010

Vermont

No legislative or regulatory policy activity during the review period was known to the reviewers.

Virginia

REGULATORY:

Special Commission Recommends Demand Response

In December 2007, Governor Kaine established the Governor's Commission on Climate Change. In November 2008, the Governor's Commission on Climate Change held its ninth meeting and discussed its draft recommendations for Governor Kaine. Among the roughly 100 draft recommendations are two that address demand response:

- "Electric utilities should pilot voluntary real-time rates to residential and commercial customers to understand the effect such rates would have on their cost structure and ensure costs are not shifted between time-of-use and other customers. After testing in pilots, these rates should be made available to all residential and commercial customers."

- "The General Assembly should enact legislation to encourage development of utility conservation programs. Such legislation should provide for the timely recovery of (i) prudent electric utility operational expenditures for energy efficiency and demand management actions, and (ii) prudent electric utility capital investments, which should subject to the same enhanced return as clean energy supply options (200 basis points above the approved electric utility-wide allowable rate of return)."

In December 2008, the group met for the last time and approved its final recommendations.

EISA 2007 PURPA Standards

The Virginia Corporation Commission initiated a proceeding in December 2008 to consider whether to adopt the four PURPA Standards created by the Energy Independence & Security Act of 2007. Two of the four PURPA Standards under consideration address the smart grid: the Smart Grid Investments Standard and the Smart Grid Information Standard. In the initiating Order, the Commission solicited comments about the following issues:

1. "whether the Commission has the authority to consider these four standards and whether the implementation of such standards would be consistent with otherwise applicable Virginia law"

2. “whether any prior state action has occurred such that standards in Section 532(a) of the Act, or comparable standards, have already been implemented or considered in the Commonwealth”

3. “whether any prior state action has occurred such that the standards in Section 1307(a) of the Act, or comparable standards, have already been implemented or considered in the Commonwealth”

4. “whether the integrated resource plans that electric utilities are obligated to develop and file with the Commission under Section 56-597 et seq. of the Code of Virginia satisfy the requirements set out in (16) of Section 532(a) of the Act”

5. “whether electric utilities over which the Commission has ratemaking authority should be required to develop rate design modifications to promote energy efficiency investments”

6. “whether electric utilities over which the Commission has ratemaking authority should demonstrate to the State that they considered an investment in a qualified smart grid system based on appropriate factors”

7. “whether electric utilities and providers over which the Commission has ratemaking authority should provide electricity purchasers with direct access, in written or electronic machine-readable form, to information such as prices, usage, sources, and intervals and projections.”

The Commission directed its Staff to file by March 2008 “its findings and recommendations” concerning the adoption of the new PURPA standards.

Demand-Response Target Proceeding

In May 2009, and in response to state law enacted in April 2009 (Senate Bill 1348), the Virginia State Corporation Commission opened a proceeding to establish cost-effective energy conservation and demand response goals for generating electric utilities. In the Initiating Order, the Commission set the procedural schedule and solicited comments and testimony:

- June 2009: Notices of participation as a respondent are due
- June 2009: Testimony from “respondent generating electric utilities” is due
- July 2009: Testimony from “all other respondents” is due

- July 2009: Comments are due
- September 2009: Commission's Staff's report is due
- September 2009: Public evidentiary hearing
- November 2009: The Commission's findings and recommendations to the Governor and General Assembly are due

LEGISLATIVE:

Peak Reduction Standard

In April 2009, Governor Kaine signed a bill that directs the State Corporation Commission to conduct a proceeding to establish cost-effective energy conservation and demand response goals for generating electric utilities. The new law has four main provisions:

(1) Directing the Commission to set conservation and demand response goals
(2) Directing the Commission to report to the Governor and the General Assembly on goals and rate recovery for DSM programs
(3) Directing the Commission to approve, if certain conditions are met, demand response programs offered by utilities or service providers
(4) Directing the State Air Pollution Control Board to approve construction permits for generating facilities that will participate in voluntary demand response programs.

Key text of the bill is below:

> *Conservation and Demand Response Goals*
>
> "That the State Corporation Commission shall conduct a formal public proceeding that will include an evidentiary hearing for the purpose of determining achievable, cost-effective energy conservation and demand response targets that can realistically be accomplished in the Commonwealth through demand-side management portfolios administered by each generating electric utility in the Commonwealth. . . . The determination of what consumption and peak load reductions can be achieved cost-effectively shall consider standard industry-recognized tests. The Commission shall determine which test should be given greatest weight when preparing a cost-benefit analysis of a demand-side management program, taking into consideration the

public interest and the potential impact on economic development in the Commonwealth."

Commission Report to Governor and General Assembly

"That the State Corporation Commission shall report its findings to the Governor and the General Assembly on or before November 15, 2009. Such report shall (i) indicate the range of consumption and peak load reductions that are potentially achievable by each generating electric utility, the range of costs that consumers would pay to achieve those reductions, and the range of financial benefits or savings that could be realized if the targets were met over a 15-year period; and (ii) determine a just and reasonable ratemaking methodology to be employed to quantify the cost responsibility of each customer class to pay for generating electric utility-administered demand-side management programs. This evaluation shall include an examination of the class cost responsibility methods used in other jurisdictions, including, but not limited to, the allocation of costs based on projected class benefits and the allocation of costs based on program participation."

Third-Party Service Providers

"That the State Corporation Commission, for the service area of a generating electric utility that has elected to meet its capacity obligations of a regional transmission entity through a fixed capacity resource requirement as an alternative to other capacity mechanisms, shall approve any demand response program proposed to be offered to retail customers by the generating electric utility or any other qualified nonutility provider if, following notice and the opportunity for a hearing, the State Corporation Commission finds (i) any nonutility provider to be qualified, (ii) the program to be effective, reliable, and verifiable as a capacity resource, and (iii) such program to be in the public interest. A State Corporation Commission order issued pursuant to this section shall not affect any contract between a retail customer and a curtailment service provider executed prior to July 1, 2009."

State Air Pollution Control Board

"That the State Air Pollution Control Board, in consultation with the State Corporation Commission and the Department of Mines, Minerals and Energy, shall adopt an air general permit or permits for the construction, installation, and operation of distillate oil, natural gas, liquid propane gas, and bio-diesel fired electric generating facilities

> that participate in a voluntary demand response program (i.e. load curtailment, demand response, peak shaving or like program) and that qualify as non-major facilities under the Clean Air Act Amendments of 1990. Participation in PJM Interconnection LLC's Emergency Load Response Program, as defined in PJM Interconnection LLC's Manual 13 Emergency Operations, shall not be considered as participating in a voluntary load reduction program."

<u>Efficiency Legislation Includes Demand Response and Smart Grid</u>

Energy-efficiency legislation was introduced in January 2010 in the Virginia Senate that would require the Virginia State Corporation Commission to biennially review "the rates, terms and conditions for the provision of generation, distribution and transmission services by each investor-owned incumbent electric utility." The bill's definition of an "energy efficiency program" includes demand response and measures "such as but not limited to the installation of advanced meters, implemented or installed by utilities, that reduce fuel use or losses of electricity and otherwise improve internal operating efficiency in generation, transmission, and distribution systems." The legislative language also says that the costs of demand response programs, which are "approved by the Federal Energy Regulatory Commission and administered by the regional transmission entity of which the utility is a member," are to be deemed "reasonable and prudent." Finally, there is a provision that would allow a utility to petition, no more than once a year, for rate adjustments that would cover the "projected and actual costs for the utility to design and operate fair and effective peak-shaving programs."

<u>Bill in Support of Smart Metering</u>

In January 2009 a bill was filed in the Virginia General Assembly that would request the State Corporation Commission to study the "advisability of increasing the implementation of smart meter technologies in the Commonwealth." The legislation says:

> "In conducting its study, the Commission shall (i) examine the deployment of smart meter technologies in other states; (ii) evaluate alternative metering infrastructure that will allow utilities to communicate with customers in a manner that allows customers to reduce usage in response to high demand; and (iii) recommend measures to address costs of meters and other equipment replaced by smart meter technologies.

> "All agencies of the Commonwealth shall provide assistance to the State Corporation Commission for this study, upon request."

The Commission would be required to file a report of its study and any recommendations stemming from it with the Governor and General Assembly.

No action on this legislation since its introduction was identified for this report.

Washington

REGULATORY:

In March 2009 the Washington State Utilities and Transportation Commission opened a proceeding to consider whether to adopt the four PURPA Standards created by the Energy Independence & Security Act (EISA) 2007. In September 2009, the Commission issued an Order in which it announced its decision to not adopt three of the four PURPA standards. The Commission said that the docket would remain open for the fourth standard, Standard 18(A)—the standard that would require utilities to demonstrate, prior to undertaking investments in non-advanced grid technologies, that they have considered investments in "qualified smart grid systems" based on a list of factors. Later in September 2009, the Commission issued a Notice soliciting comments on a "discussion draft of a proposed rule relating to PURPA Standard 18(A)." Comments were due in October 2009. In December 2009, the Commission announced the release of a Proposed Rule on the standard and solicited comments about it. The Proposed Rule calls for each utility to "file with the commission a smart grid technology report no later than September 1, 2010, and a subsequent report no later than September 1st of each even-numbered year thereafter through September 2016." Comments were due January 2010. Furthermore, the Commission announced a public hearing on the Proposed Rule for February 2010.

LEGISLATIVE:

In February 2007, smart grid legislation was introduced into Washington State Senate. If passed, the legislation would do the following:

- Require the Washington State Department of Community, Trade, and Economic Development (CTED) to adopt rules by December 2008 creating a "tax credit certification process for smart grid energy technologies that promise to significantly improve the reliability, efficiency, and environmental integrity of electrical transmission and distribution systems."

- Provide tax exemptions for the purchase, installation, and use of smart meters.
- Require the State Energy Office and the CTED to develop a plan to promote efficient use of electrical and transmission systems, which would include "proposals for creating and strengthening public and private partnerships to promote smart grid energy improvements…and enhancement of smart grid business development in Washington state."

In January 2008, January 2010, and March 2010, the Senate passed resolutions to reintroduce and retain "in present status" the bill.

No subsequent activity regarding the legislation was identified for this report.

Green Legislative Agenda, Including PHEV Support

In January 2009 Governor Gregoire and state legislators launched a green-job and climate-change legislative initiative with the goals of reducing greenhouse-gas emission to 1990 levels by 2020; to 25% below 1990 levels by 2035; and to 50% below 1990 levels by 2050. The initiative is based on investing $455 million over two years in transportation, energy-efficiency, green-building, and clean-energy-technology projects. Of this amount, $20 million is to support clean-technology infrastructure and $10 million is to fund energy efficiency and renewable energy in public facilities and public housing. The Governor predicts the $455 million investment will "support" 2,900 jobs in 2010 and 2011. There is no indication whether this money is to fund smart grid technologies or demand response programs. Plug-in hybrid electric vehicles, however, are part of the Governor's legislative agenda.

PHEV Legislation

In January 2009, two bills were introduced into the Washington State House of Representatives that would support the development of plug-in hybrid vehicles (PHEVs). The first notes the benefits of PHEVs: "Plug-in vehicles not only dramatically reduce carbon loading in the atmosphere, but their use also provides electric utilities with the advantages of distributed generation that can be utilized on demand by the utility." This bill would appropriate $213,000 to support PHEV research at a state college. The second bill would wave a state sales tax on PHEVs until 2014. In January and March 2010, both bills were "reintroduced and retained in present status." No additional action was identified for this report.

West Virginia

REGULATORY:

EISA 2007 PURPA Standards

In December 2009 the West Virginia Public Service Commission issued an Order determining that it would not adopt the Smart Grid Investment Standard, the Smart Grid Information Standard, and the other two PURPA standards established by the Energy Independence and Security Act (EISA) 2007. Instead, the Commission adopted the Joint Stipulation agreement filed in August 2009 by all parties to the proceeding---including the Commission's Staff, its Consumer Advocate Division, utilities, and electricity customers---which recommended passing over the four PURPA standards. The Joint Stipulation, however, does indirectly support the smart grid. Passages from it include:

- "The electric utilities participating in the Joint Stipulation agree to make a yearly informational filing as a closed filing in this case starting six months after the entry of a final order in this case which provides a summary and data from any smart grid pilot programs they are implementing in West Virginia or that are being implemented by the electric utility and/or its subsidiaries and/or affiliates in other jurisdictions in order to inform the Commission of results obtained from such smart grid pilot programs."

- "AP [Allegheny Power] shall file as a closed filing in this case a copy of the final report of the West Virginia Smart Grid Implementation Team that is being led by the National Energy Technology Laboratory (NETL) when it is available."

- "The electric utilities participating in this Joint Stipulation, excluding utilities that change their rates pursuant to W. Va. Code 524-2-4'0, shall in future base rate case filings include, either as part of the State of the Art Report made with the initial filing or as a separate filing within the rate case filing, a summary of the smart grid considerations the utility has made in West Virginia and an explanation as to why the utility is or is not implementing such technology at that time."

LEGISLATIVE:

Portfolio Standard that Includes Demand Response and Smart Grid

In June 2009 Governor Manchin signed West Virginia's Alternative and Renewable Energy Portfolio Act, creating "a system of tradable credits to establish, verify and monitor the generation and sale of electricity generated from alternative and renewable energy resource facilities." Specifically, the new law awards credits for electricity produced from alternative and renewable resources as well as for energy conserved as a result of energy efficiency and DSM projects, including demand response and the smart grid. The law defines an "energy efficiency or demand-side energy initiative project" to be one that "promotes customer energy efficiency or the management of customer consumption of electricity through the implementation of":

- "Load management or demand response technologies, equipment, management practices, interruptible or curtailable tariffs, energy storage devices or other strategies in residential, commercial, industrial, institutional and government customers that shift electric load from periods of higher demand to periods of lower demand"

- "Customer-sited generation, demand-response, energy efficiency or peak demand reduction capabilities, whether new or existing, that the customer commits for integration into the electric utility's demand-response, energy efficiency or peak demand reduction programs"

- "Infrastructure and modernization projects that help promote energy efficiency, reduce energy losses or shift load from periods of higher demand to periods of lower demand, including the modernization of metering and communications (also known as "smart grid"), distribution automation, energy storage, distributed energy resources and investments to promote the electrification of transportation."

Wisconsin

REGULATORY:

Biennial Strategic Energy Assessment

In April 2009 the Wisconsin Public Service Commission released its fifth biennial strategic energy assessment, "Energy 2014: Ensuring the Availability, Reliability and Sustainability of Wisconsin's Electric Energy Supply." The assessment, according to the Commission, “provides a picture of past and future electric energy needs and sources of supply” and “brings to light issues that may need to be addressed to ensure the availability, reliability, and sustainability of Wisconsin’s electric energy supply.” It concludes, among other things, that peak demand will grow between 2009 and 2014 at an average annual rate of 2.10%. This growth rate is about equal to 500 MW every two years. The assessment also finds that demand response (interruptible load, in particular) will provide roughly 4% of the state’s electricity supply by 2014. By the same year, over 3,000 MW of new generating capacity is to be available.

Load Management & Governor’s Task Force of Global Warming

In April 2008, the Wisconsin Public Service Commission began a proceeding to "develop and analyze load management options in accordance with the recommendations of the Governor's Task Force on Global Warming.” In April 2009, it issued an Amended Notice of Investigation in which it added to the scope of the proceeding the consideration of the “potential advantages and disadvantages” of allowing Aggregators of Retail Customers (ARCs) to bid demand response resources from retail customers directly into ISO/RTO wholesale markets. The Commission decided to broaden the proceeding in response to FERC’s Order 719 in Dockets RM07-19 and AD07-7 (“Wholesale Competition in Regions with Organized Electric Markets”). FERC’s October 2008 Order 719 stipulated that ISOs/RTOs must change their market rules so as to allow ARCs to bid demand response resources from retail customers directly into their markets. In the April 2009 Notice, the Commission solicited requests for hearings and comments on “whether and to what extent it should prohibit the participation of ARCs in Wisconsin, until such time as it has had an adequate opportunity to investigate these issues and provide for the development and implementation of any needed modifications to existing demand response programs and retail rate structures.” Comments were filed in April and May 2009.

In October 2009, the Commission issued an Order temporarily prohibiting the operation of ARCs in the state “in order to prevent potential unlawful discrimination and to permit the Commission additional time to gather more information regarding ARCs, ARC compensation and the tariff provisions of the Midwest Independent Transmission System Operator, Inc. (MISO).” The Commission explained, “Temporarily prohibiting ARCs will provide the Commission with an opportunity to analyze the financial implications that ARCs may have for Wisconsin ratepayers and electric utilities and to investigate the effects that ARCs may have on utility-sponsored demand response programs and utility planning.”

Wyoming

No legislative or regulatory policy activity during the review period was known to the reviewers.