Demand Response & Smart Grid—State Legislative and Regulatory Policy Action Review: May 2010 – June 2011

An Overview

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June 2011

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Acronyms

AMI = Advanced Metering Infrastructure

CAISO = California ISO

DSM = Demand-Side Management

EISA = Energy Independence and Security Act of 2007

EEPS = Energy Efficiency Portfolio Standard

EM&V = Evaluation, Measurement, and Verification

ERCOT = Electric Reliability Council of Texas

FERC = Federal Energy Regulatory Commission

ISO = Independent System Operator

MISO = Midwest ISO

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

REPS = Renewable Energy Portfolio Standard

RTO = Regional Transmission Organization

RTP = Real-Time Pricing

TOU = Time of Use

Overview

This report, “Demand Response & Smart Grid—State Legislative and Regulatory Policy Action Review: May 2010 – June 2011,” is an overview of state-level legislative and regulatory policy developments on demand response, smart metering, and smart grid. Prepared by the Association for Demand Response & Smart Grid (ADS), it catalogues efforts undertaken by state regulatory commissions, state agencies, and state legislatures. While the new report does not directly cover any federal activity, it does discuss FERC, DOE, and NIST actions as they relate to and affect state policy efforts. It also covers state actions in response to the two smart grid PURPA Standards established by the Energy Independence & Security Act of 2007 (EISA) and the DOE Smart Grid Grants funded under the American Recovery and Reinvestment Act of 2009.

This report builds off two previous reports similar in scope prepared by the ADS under its previous name, the Demand Response Coordinating Committee (DRCC). The 2008 policy survey, “Demand Response and Smart Metering Policy Actions Since the Energy Policy Act of 2005: A Summary for State Officials,” which was prepared for The National Council on Electricity Policy, covered state and federal policy developments 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 2010 policy survey, “Demand Response & Smart Grid—State Legislative and Regulatory Policy Action Review: October 2008 – May 2010,” covered ongoing EPACT 2005 implementation efforts as well as the consideration by state regulatory commissions of the two smart grid PURPA Standards established by the EISA 2007.

Regarding the methodology and scope of this report:

- It is based on the best public information that was available as of June 2011 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 regarding energy efficiency, renewable energy, and other tangential topics only when they directly mention demand response, smart grid, smart meters, AMI, energy storage, or other pertinent subjects. Accordingly there may have been policy developments in such tangential 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 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 ADS archive of demand response and smart grid regulatory and legislative activity. The next step was to revisit the primary sources of information—in most cases, the online library of state legislatures and public utility commissions—and to review the documentation of known activities to determine whether there had been any additional developments. The final stage was to investigate any leads for regulatory or legislative activity previously unknown by ADS.

This report demonstrates that there continues to be a substantial amount of state policymaking related to demand response and smart grid. 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: May 2010 – June 2011"—as well as the two previous ADS policy-survey reports –can be accessed on the ADS website.

http://www.demandresponsesmartgrid.org/reports-research/ads-reports

The Association for Demand Response & Smart Grid (ADS) is a nonprofit organization, originally formed as the Demand Response Coordinating Committee (DRCC) in 2004. ADS is an organization consisting of professionals and organizations involved in demand response and smart grid. It provides services to meet the needs of its members that help them in the conduct of their work and in the attainment of their personal, corporate, and governmental objectives. ADS seeks to establish and grow a demand response "community" of policymakers, utilities, system operators, technology companies, consumers, and other stakeholders.

ADS Group Members

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Pacific Gas & Electric * PECO * PJM Interconnection * Progress Energy
Salt River Project * San Diego Gas & Electric * Southern California Edison
Southern Company * Tennessee Valley Authority * Walmart

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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:

EEPS of 22% by 2020 (Includes Demand Response)

January 2010: Commission issued NOPR proposing new EEPS rules.

July 2010: Commission approved new rules setting an Energy-Efficiency Portfolio Standard (EEPS) of reducing annual electricity consumption (KWh) by 22% by 2020. Demand response and load management, according to the January 2010 NOPR proposing the rules, "may comprise up to two percentage points of the 22% energy efficiency standard, with peak demand reduction capability from demand response converted to an annual energy savings equivalent based on an assumed 50% annual load factor.” Furthermore, “the credit for demand response and load management peak demand reductions shall not exceed 10% of the energy efficiency standard” for any year. The rules also require utilities to file every two years plans for cost-effective DSM programs (including energy efficiency, load management, and demand response) that are to meet the EEPS. Once the plans are approved and in effect, the utilities are to file with the Commission in March of every year progress reports about their DSM programs. Upon approval of the rules, the Commission sent them to the Arizona Attorney General for approval.

LEGISLATIVE:

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

Arkansas

REGULATORY:

Investigative Proceeding on Smart Grid, AMI, and Demand Response

December 2010: Commission issued an Order opening an investigative proceeding on smart grid, AMI, and demand response. The new case is born of the Commission’s proceeding to develop a Sustainable Energy Resources Action Plan, which 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.” When the Commission issued the Sustainable Energy Resources Action Plan (in December 2010) it also opened a series of new dockets to realize the goals set by the Action Plan. This proceeding is one of them.

LEGISLATIVE:

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

California

REGULATORY:

Smart Grid Proceeding

Background: This proceeding began in December 2008 as the Commission's effort to consider the adoption of the two smart grid PURPA Standards established by the Energy Independence & Security Act of 2007. The initial scope of the proceeding included the state's policies for the smart grid and what the smart grid enables, including greater deployment of demand response. In December 2009 the Commission issued a Decision declining to adopt the Smart Grid Investment PURPA Standard and the Smart Grid Information PURPA Standard established by EISA 2007. The December 2009 Decision, however, did adopt policies for IOUs that support smart metering, smart grid, and demand response. In February 2010 the California Public Utilities Commission issued a Ruling that revised the procedural schedule and amended the scope of the proceeding so as to include the issues the Commission is to consider per Senate Bill 17, a law signed in October 2009 that directed IOUs and municipal utilities to file smart grid deployment plans with the Commission by July 2011.

March and April 2010: Comments and reply comments due 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."

March 2010: Two workshops focusing on "Smart Grid Deployment Plan Requirements" and "Access to Electricity Prices & Usage."

May 2010: Commission issued a Proposed Decision that would provide IOUs 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."

June 2010: Commission approved the Proposed Decision, thereby providing IOUs with guidance for filing smart grid deployment plans by July 2011 in compliance with Senate Bill 17. In approving the Proposed Decision, the Commission provided:

- "Smart Grid Vision Statement to help orient a utility's efforts to upgrade its electrical system to meet today's requirements and tomorrow's needs using the latest technologies."

- "Smart Grid Strategy to consider whether using existing communications infrastructure can reduce the costs of deploying the Smart Grid."

- "Grid Security and Cyber Security Strategy to ensure that these issues are considered explicitly at the planning stage."

- "Cost Estimates of Smart Grid technologies and infrastructure investments that a utility expects to make in the next five years, and provisional cost ranges for potential Smart Grid technologies and investments for the following five years."

- "Metrics that permit the assessment of progress."

July 2010: Commission issued a Ruling proposing revised smart grid metrics that would provide a benchmark against which to measure whether the IOUs are complying with the policies established in the June Final Decision. This Ruling also solicited comments and scheduled a Prehearing Conference to address “issues relating to data privacy, security of the Smart Grid, and access to data by customers and third parties.”

September 2010: Commission issued Ruling setting the schedule for “resolving issues of privacy and security that arise in providing a consumer and third parties . . . with access to data on the consumer’s electricity usage and the prices that the consumer pays for electricity.” Specifically, the Ruling posed a set of questions for IOUs to answer in October 2010. These questions are:

- “What customer energy usage data does the utility expect to generate or currently generates (including the frequency with which such data will be generated)? Does the utility provide customers with access to that data today? If not, when is the target date for providing such access? With whom do you propose to share that data? How do you currently use such data (including the relevance of such data to the intended uses), and how long will the data be maintained?”

- “What are the current privacy protections and data exchange rules that apply to this data? What privacy protections and data exchange rules does the utility propose that the Commission adopt?”

- “Does the utility currently provide usage data to third parties? If so, what are the consumer protections and security provisions that apply to that information? What policies do the utility follow in responding to requests or demands for disclosure of such data from law enforcement, other government agencies, and civil litigants, including what policies will the utility follow in providing consumers with notice when a request or demand is received?”

- “Does the utility provide the customer with access to pricing data associated with their usage? If so, what does the utility communicate and when and how is the price communicated? What price information does the utility believe would be most useful to a customer?”

The Ruling also solicited comments from third parties “wishing to obtain access to customer information.” These comments were also due in October 2010, and they were to answer these questions:

- “What home energy usage data do third parties currently obtain, expect to obtain, or will seek to obtain? How does the third-party use or expect to use the data (including the relevance of the data for the expected uses)? To whom do third parties expect to disclose the data, and how long will the data be maintained? How does a third-party expect to obtain information, e.g., via the meter, a utility webpage or some other means?"

- "What policies do third parties follow when responding to requests or demands for disclosure of such data from law enforcement, other government agencies, and civil litigants, including what policies will the third-party follow in providing consumers with notice when a request or demand is received?"

Finally, the September 2010 Ruling solicited proposals for providing customers "with access to their usage and price data while protecting the security of the data and the privacy of customers." The Ruling also requested proposals about what prices to communicate to customers relative to the Commission's policy goal of providing "consumers with access to electricity price information by the end of 2010." These proposals were due in October 2010.

October 2010: IOUs' answers to Commission's 10/15/10 questions due; comments due from third parties "wishing to obtain access to customer information"; proposals due for providing customers "with access to their usage and price data while protecting the security of the data and the privacy of customers."

October 2010: Commission workshop.

October 2010: Commission issued Ruling soliciting "legal briefs addressing two questions":

- "What authority does the Commission have over entities that receive information on a consumer's energy usage from the utility? What actions, if any, can the Commission take in response to misuse of data by such an entity?"

- "What authority, if any, does the Commission have over entities that receive information on a consumer's energy usage from sources other than the utility (from a Home Area Network device or from the customer, for example)? What actions, if any, can the Commission take in response to misuse of data by such an entity?"

November 2010: Reply comments—relative to initial comments, the proposals filed, or the workshop's discussion—due.

December 2010: Commission issued Ruling soliciting comments on metrics by which to measure the progress of IOUs in implementing a smart grid. Comments due January 2011; reply comments due February 2011. More specifically, the Commission wants feedback on the proposals floated in an October 2010 report, "Report on Consensus and Non-Consensus Smart Grid Metrics," collectively developed by the utilities. Feedback is sought on the following:

- "Are these [consensus] metrics [which cover AMI, PHEV, storage, and grid operations] appropriate and reasonable? Will the information that these metrics yield efficiently and effectively serve the public interest. Additionally, do these consensus metrics appropriately reflect the input of parties?"

- Are the items deemed "Non-Consensus"—which include "measurement of benefits and capabilities of the Smart Grid" and "certain topics including Customer/AMI Metrics, Advanced Automation and Measurement Technologies, Cyber Security, Plug-in Electric Vehicles, Energy Storage, and Environmental Metrics"—presented accurately? "What recommendations do parties have for creating metrics or addressing the issues and topics covered in this section?"

- Should the Commission Staff's proposal of creating a Technical Working Group, which would be charged with conducting "a dialogue concerning cyber security metrics," be realized? How would the proposed Technical Working Group operate?

- What is the "best process to review and revise these metrics in the future"? "Should a Technical Working Group be convened by topics? Should the Commission hold a workshop at a later date to discuss any potential revisions?" Should there be "a workshop or additional informal meetings . . . held prior to the October 2012 deadline for the utilities' first annual report"?

- What is "the appropriate reporting period"?

<u>January 2011</u>: Comments due.

<u>February 2011</u>: Reply comments due.

<u>March 2011</u>: Public meeting to consider the draft Smart Grid Deployment Plans filed by IOUs. The goal of the meeting was to enable the California Energy Commission and CAISO to provide feedback on the plans.

<u>May 2011</u>: Proposed Decision that, if approved, would adopt rules "to protect the privacy and security of customer usage data generated by Smart Meters"

as well as establish "policies to govern access to customer usage data by customers and by authorized third parties." Specifically, the Proposed Decision would do the following:

- Direct utilities to file, within six months, "a Tier 3 advice letter including tariff changes to make price, usage and cost information available to its customers online. The information must be updated at least on a daily basis, with each day's usage data, along with applicable price and cost details and with hourly or 15-minute granularity (matching the time granularity programmed into the customer's smart meter), available by the next day. The tariff changes must offer residential customers bill-to-date, bill forecast data, projected month-end tiered rate, a rate calculator and notifications as the customers cross rate tiers as part of the pricing data provided to customers. The prices must state an 'all in' price the customers pay for electricity."

- Direct utilities to "each file an advice letter within six months that creates a tariff to provide third parties, with customer authorization, with usage and billing information consistent with the polices and rules adopted to protect the privacy of customers."

- Adopt "a framework to allow customers to authorize third parties who agree to comply with the adopted privacy and security rules to receive usage data from utilities via the 'backhaul.'"

- Direct utilities to "work with the California Independent System Operator in developing a methodology to make wholesale prices available to customers on each company's website."

- Direct utilities to commence, within six months, two pilot studies:

  - "a pilot study to provide price information to customers in real time or near–real time"

  - "a pilot study and trial that permit Home Area Network-enabled devices to be connected directly with Smart Meters."

- Adopt "reporting and audit requirements regarding the utilities' customer data privacy and security practices, third-party access to customer usage information, and any security breaches of customer usage information":

  - Beginning in 2012, utilities would have to file annual privacy reports

- o Each utility would have to “conduct independent audits of its data privacy and security practices” and would have to file its “audit findings as part of each general rate case application filed after 2012.”

June 2011: Comments on Proposed Decision due.

June 2011: Reply Comments on Proposed Decision due.

DR Load Impact Estimates, CAISO, & 2012 – 2014 DR Applications

Since January 2007: Commission has been conducting a proceeding to address specific issues related to developing effective demand response programs for IOUs. The proceeding so far has had three phases.

July 2008: Phase III began when the Commission decided to address the “operation of the investor-owned utilities’ emergency-triggered DR programs in the future electricity wholesale market.”

August 2008: Prehearing conference.

August and October 2009: Workshops held 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.”

January 2010: Settlement conference.

February 2010: Joint motion proposing 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, they 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.”

May 2010: Commission issued a Proposed Decision that would adopt a Settlement Agreement that “transitions many of the current reliability-based and emergency-triggered demand response programs into price-responsive demand response products.” Signatories of the settlement agreement were CAISO; California Large Energy Consumers Association; the Commission's Division of Ratepayer Advocates; EnerNOC; PG&E, SDG&E; SCE; and The Utility Reform Network.

June 2010: Commission issued a Final Decision through which it established the "initial conditions" for its oversight of direct bidding of retail demand response into the CAISO market. The Commission directed IOUs to make preparations for bidding demand response from existing Participating Load Pilot Programs into CAISO's wholesale market "as soon as is feasible if the FERC approves tariff language that is acceptable to the CPUC." The Commission, however, prohibited "further participation by IOU retail customers" until it creates "ratepayer protections and other relevant rules and protocols." The Final Decision was in response to FERC's Order 719 in (in Dockets AD07-7 and RM07-19, "Wholesale Competition in Regions with Organized Electric Markets"), which required CAISO to modify its tariffs so as "to allow retail customers to bid Demand Response (DR) directly into their wholesale electric and ancillary services markets, either on their own behalf or through aggregators, if the relevant state or regional authorities do not prohibit such direct bidding."

August 2010: Commission issued a Ruling in which it provided "guidance related to the scope and contents" of the 2012 – 2014 demand response applications to be filed by the IOUs. The guidance focused on the following issues:

- "The importance of price-responsive demand response."
- "Alignment of demand response program designs with resource adequacy requirements."
- "Integration of demand response with wholesale markets."
- "Implementation of a cap on emergency-triggered programs."
- "Funding for the Integrated Demand Side Management activities."
- "Additional activities related to demand response included in previous applications, including automated demand response/technology incentives, permanent load shifting, and existing and potential new pilot programs."
- "Inclusion of demand response load impact estimates."
- "Inclusion of demand response cost effectiveness analyses."
- "Inclusion of information on demand response activities authorized in other proceedings."
- "The contents and format of the utilities' Applications."

Furthermore, the Commission says that the IOUs are to propose how to improve existing demand response programs so as to make them more cost-effective and to "enhance their integration with California electric markets and resource adequacy requirements."

<u>August 2010</u>: Commission solicited comments "on whether and to what extent the Investor Owned Utilities should be approved to bid their Participating Load Pilot programs as Proxy Demand Resources." Comments were due in August 2010 and reply comments in September 2010. Commission solicited the comments in response to FERC's July 2010 approval of CAISO's Proxy Demand Resource Tariff.

<u>October 2010</u>: Commission issued Proposed Decision suggesting that demand response "activities supported by incentives and rate exemptions funded by ratepayers of" PG&E, SDG&E, and SCE "be analyzed using the four cost-effectiveness tests described in this decision, namely, the Participant Test, the Total Resource Cost Test, the Ratepayer Impact Measure, and the Program Administrator Cost Test."

<u>November 2010</u>: Commission issued Proposed Decision recommending that the Commission authorize the utilities "to participate in bidding of the California Independent System Operator's (CAISO) Proxy Demand Resource product into the CAISO wholesale markets subject to conditions discussed in prior and upcoming decisions and Advice Letters."

<u>January 2011</u>: Commission workshop to review the Straw Proposals on Financial Settlement and Communication Protocols and related comments filed in December 2010 per its November 2010 solicitation.

<u>February 2011</u>: IOUs filed reports about the workshop.

<u>February 2011</u>: Comments on IOUs' reports due.

<u>February 2011</u>: Commission issued Ruling soliciting comments on a report about "Permanent Load Shifting (PLS) activities" that was filed in November 2010 by Southern California Edison on behalf of itself and Pacific Gas & Electric and San Diego Gas & Electric. Comments and reply comments due March 2011. The Ruling also said that IOUs are to "provide analysis of existing PLS activities and proposals for new PLS activities" in their 2012 – 2014 DR Applications. These applications were due in March 2011.

<u>February 2011</u>: Commission issued Ruling setting "guidance for the development of direct participation rules, forms, and requirements." The guidance builds off a June 2010 Final Decision that established the "initial conditions" for the Commission's oversight of direct bidding by third parties of retail DR. The June 2010 Decision also said that several issues needed to be

resolved before the Commission would allow direct bidding. To that end, the Ruling established a procedural schedule.

February 2011: Reply comments on IOUs' reports due.

March 2011: Draft due of the direct participation rules the IOUs are to develop jointly that will govern PDR-related interactions between IOUs and third-party DRPs, between IOUs (acting as a DRP) and non-IOU LSEs, and with end-use customers. Draft rules to address: (1) Direct participation rules that will be filed as IOU tariffs; (2) Pro forma service agreements for use between IOUs and DRPs; and (3) Commission registration and other consumer protection rules for DRPs.

March 2011: Deadline for Energy Division to "staff and establish a working group or groups to develop direct participation rules that will govern PDR-related interactions between IOUs and third-party DRPs, between IOUs (acting as a DRP) and non-IOU LSEs, and with end-use customers."

March 2011: Both PG&E and SDG&E filed reports on demand response load impact in 2010.

April 2011: Each IOU filed an "executive summary and accompanying appendices" for their final 2010 demand response load-impact reports.

April 2011: IOUs filed Joint Motion asking the Commission to delay issuance of a Proposed Decision on "financial compensation rules between DRPs, LSEs and retail end-use customers in accordance with the Proxy Demand Resource (PDR) rules that FERC previously held to be just and reasonable." The IOUs filed their request in response to FERC's March 2011 Final Rule requiring ISOs and RTOs to pay full LMP for demand response resources (FERC Docket RM10-17). The Proposed Decision is to be issued in late May, a timeline, the IOUs argue, that "should be held in abeyance because the scope and import of FERC Order 745 are uncertain." The IOUs are calling for a deferral until FERC provides more clarity.

April 2011: Commission filed with FERC a "Request for Clarification or, in the Alternative, Request for Rehearing" in response to FERC's Order 745 directing ISOs and RTOs to pay full LMP for demand response resources. In its filing, the Commission argued that FERC's Order 745 may be interpreted to conflict with its own directives to IOUs regarding development of Proxy Demand Resource pilot programs.

May 2011: Direct participation rules developed by working group(s) due.

May 2011: Comments on direct participation rules produced by the working group(s) due.

May 2011: In compliance with a February 2011 Ruling, two sets of proposed "direct participation rules" for bidding retailed demand response into CAISO's wholesale markets were filed. The proposed rules are "to govern interactions between IOUs, acting in their capacities of Utility Distribution Companies (UDCs), Load Serving Entities (LSEs), Demand Response Providers (DRPs), Meter Service Providers (MSPs), and Meter Data Management Agents (MDMAs) with all other entities that perform these responsibilities to provide Demand Response (DR) services to the California Independent System Operator (CAISO) through the a DR market mechanism." The first set of proposed direct participation rules was filed jointly by SCE, PG&E, and SDG&E. The proposed rules are modeled on the utilities' Direct Access rule. The utilities, however, report that they feel their proposal is insufficient. They argue, furthermore, "that the work product would benefit from more time, particularly after a Commission decision on threshold policy matters." The second set of proposed direct participation rules was filed by the members of a working group formed by the Commission's Staff. The Joint Parties, as they are known, are EnerNOC, Energy Connect, the Alliance for Retail Energy Markets, and the Direct Access Customer Coalition. Like the utilities' rule proposal, the Joint Parties' filing articulates the lack of consensus.

May 2011: Ruling amending the scope of the proceeding. The changes were in response to FERC's March 2011 Final Rule (Order 745) requiring ISOs and RTOs to pay full LMP for demand response resources (FERC Docket RM10-17). While CAISO's proxy demand response proposal already has been approved by FERC—through a July 2010 Order in Docket ER10-765—the California Commission explains that FERC's March 2011 Final Rule "calls into question whether the previously approved CAISO tariffs are permissible." As a result, the Commission amended the scope of its proceeding "to allow consideration and clarification of FERC's new rule." Specifically, the Commission said that it is necessary to extend the deadline for its proceeding. It ruled that the proceeding will be complete within 18 months, or in November 2012.

May 2011: Comments on proposed "direct participation rules" filed.

Commission Paper on Customer Benefits of Smart Metering

October 2010: Commission Staff issued a white paper reviewing the benefits of smart metering. The paper, **"**Advanced Meters: How Customers Benefit," begins by noting that smart meter deployments have been running into customer pushback due to "subpar" consumer education. It concludes by iterating how smart metering actually will benefit customers:

> "Advanced meters are the first step toward creating an advanced electrical grid (commonly referred to as the 'Smart Grid') in California. . . .
>
> "However, customers often ask "what's-in-it-for-me," and electric utilities across the country have not successfully explained the benefits of the Smart Grid and advanced meters. Advanced meters are critical infrastructure to help customers to use their electricity more efficiently. With an advanced meter, customers and the utility will have access to information about energy use in an unprecedented manner. However, simply having access to this information is not enough. Customers and the utility must utilize this information to change certain behaviors.
>
> "This increased access to information will provide an opportunity to more efficiently manage energy use. Customers need to be able to receive this information, yes, but they also need to be able to perceive benefits from the information in order for the larger goals to be realized. In addition, advanced meters are a fundamental building block in the process of updating California's aging energy infrastructure. Rebuilding a large and complex system like California's electric generation, transmission, and distribution system is a vast undertaking; it cannot be accomplished overnight. Investments and improvements must be done in a logical, phased-in approach. Installation of advanced meters is one of the first steps to be taken, and it is appropriate for it to be the first step. As more steps are taken, more and more benefits will flow to consumers."

San Francisco's Request for Smart Metering Moratorium

June 2010: Petition filed by the City and County of San Francisco requesting a moratorium on Pacific Gas & Electric's smart meter deployment.

November 2010: Commission issued a Proposed Decision through which an Administrative Law Judge recommended that the Commission deny the June 2010 petition filed by San Francisco.

December 2010: Commission issued its Decision denying San Francisco's petition requesting a suspension of Pacific Gas & Electric's smart meter deployment. The Commission said that San Francisco did "not put forth facts that justify the requested action." The Commission continued, "In particular, there are no facts that show that the Smart Meters are less accurate than current meters or that the billing system is now generating fewer accurate bills." Additionally, the Commission explained that because other issues in the proceeding "have had, have, and will likely have other procedural homes," there is no reason to address them in this proceeding.

Investigation of Health Concerns of Smart Meters

April 2010: Commission began proceeding in response to an application filed by the EMF Safety Network. The EMF Safety Network's filing requested that "the Commission examine the health and safety impacts of radio frequency (RF) emissions from Pacific Gas and Electric Company's (PG&E) SmartMeter system."

November 2010: The California Division of Ratepayer Advocate (DRA) filed comments arguing that the Commission should investigate whether smart metering poses health risks to utility customers. The DRA said, "Health and safety concerns of customers who have SmartMeters need to be addressed, so that they will be willing to make use of the enabling technology. Unless the public's concerns can be put to rest, there is a very great risk that PG&E's SmartMeter deployment will turn out to be a $2.2 billion mistake that ratepayers can ill afford."

December 2010: Commission issued a Final Decision dismissing the EMF Safety Network's motion to overturn the Commission's Decisions to approve Pacific Gas & Electric's smart metering program. Regarding the EMF Safety Network's concern about the potential danger of smart metering, the Commission concluded:

> "The radio frequency (RF) emissions from Smart Meters that the EMF Safety Network wishes the Commission to investigate are one/six thousandth of the Federal health standard at a distance of 10 feet from the Smart Meter and far below the RF emissions of many commonly used devices. It is therefore not reasonable to reopen our prior Smart

Meter decisions to address the alleged health impacts produced by RF emissions from Smart Meters."

Elsewhere, the Commission noted that the questions about RF emissions fall within the purview of the Federal Communications Commission.

The Final Decision closed the proceeding.

January 2011: The EMF Safety Network filed an Application for Rehearing, seeking a second consideration of the Commission's December 2010 decision. In the application, the EMF Safety Network argued that "the Commission should reopen its review of Smart Meters, order an immediate moratorium on the deployment of Smart Meters, hold public evidentiary hearings, offer shielded wire alternatives or maintain existing electromechanical meters to ensure that the Smart Meter program is consistent with delivery of safe, gas and electric service."

January 2011: PG&E filed a response to the EMF Safety Networks Application for Rehearing. PG&E requested that the Commission deny the Application for Rehearing.

Petition Seeking Time-Stamp Requirement for Smart Grid Transactions

December 2010: Commission denied a petition filed in July 2010 requesting that the Commission initiate a rulemaking proceeding "to establish a minimum level of competence for any and all digital information systems and all components used in the Smart Grid." The petition suggested that "any and all SmartGrid monitoring processes must also produce court admissible evidence of operations which meets the minimum legal standards for digital evidence both at the State of California's level and that of the Federal Government." It also noted that the "inclusion of a third party, to generate and officiate those evidentiary grade time stamps as part of every transaction[,] is another potential key-step towards assuring compliance with the state and federal evidentiary standards." The Commission's denial of the July petition is due to the petition's failure "to comply with Commission Rules of Practice and Procedure" and "to make a persuasive argument that opening a rulemaking on this issue could provide ratepayer benefits in excess of costs or could advance a statutory goal." To the point, the Final Decision's Findings of Fact are:

1. "The Petition fails to include specific proposed wording for the regulations to implement the policy changes that it requests."

2. “The Petition lacks clarity.”

3. “The Petition fails to concisely state the justification for the requested relief.”

4. “The Petition does not provide facts that demonstrate that ratepayers would benefit from the opening of a rulemaking to consider Commission adoption of new standards applicable to the data collected by the SmartGrid and used in Commission proceedings.”

5. “The Petition does not demonstrate that requiring the SmartGrid’s component systems and the information generated to meet evidentiary standards that appear to prevail in California trial courts, with law enforcement agencies, and with municipalities employing automated enforcement systems.”

California Energy Commission Grants

December 2010: The California Energy Commission awarded a $400,000 grant to a project whose goal is “to demonstrate the benefits of using energy storage systems in conjunction with an on-site fuel cell power generation.” The funding comes from the Commission’s Public Interest Energy Research (PIER) program.

December 2010: The California Energy Commission awarded a $1.2 million grant to an electric vehicle project.

December 2010: The California Energy Commission awarded $325,000 to the University of California’s California Institute for Energy and Environment (CIEE) to support a “strategic analysis of energy storage technology” and the development of a “2020 energy storage vision for the state.” The Energy Commission says that the CIEE project will yield results that will help the California Public Utilities Commission as it creates “specific energy storage policies for California utilities” in compliance with Assembly Bill 2514 of 2010.

Health Impacts of Smart Metering

January 2011: The California Council on Science and Technology (CCST), a nonpartisan and nonprofit organization established by the California legislature, published a report evaluating the health impacts of smart metering that it developed in response to requests from several members of the State Assembly. The report assesses available scientific evidence on two issues: (1) “Whether FCC standards for Smart Meters are sufficiently protective of public health taking into account current exposure levels to radiofrequency and electromagnetic fields” and (2) “Whether additional technology specific standards are needed for SmartMeters and other devices that are commonly found in and around homes, to ensure adequate protection from adverse health effects.” The CCST developed the report by consulting with “over two dozen experts” and by reviewing “hundreds of articles and reports.” It did not conduct its own primary research, instead relying on “the body of existing *generally accepted scientific knowledge* regarding smart meters and similar electronic devices.” Key findings in the report include:

- “Wireless smart meters, when installed and properly maintained, result in much smaller levels of radio frequency (RF) exposure than many existing common household electronic devices, particularly cell phones and microwave ovens.”

- “The FCC standard provides a currently accepted factor of safety against known thermally induced health impacts of smart meters and other electronic devices in the same range of RF emissions. Exposure levels from smart meters are well below the thresholds for such effects.”

- A typical smart meter that operates on a 5% duty cycle, transmitting radio frequency 72 minutes each day, will yield RF exposure that is just 3% of the FCC limit. A smart meter operating on a 100% duty cycle (transmitting 24 hours a day), meanwhile, will yield RF exposure that is 60% of the FCC limit.

- “To date, scientific studies have not identified or confirmed negative health effects from *potential non-thermal* impacts of RF emissions such as those produced by existing common household electronic devices and smart meters.”

- “Not enough is currently known about potential non-thermal impacts of radio frequency emissions to identify or recommend additional standards for such impacts.”

Electric Vehicles

May 2010: Commission issued a Proposed Decision suggesting 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.

July 2010: Commission adopted the May 2010 Proposed Decision, thus declaring that the people and facilities selling electric vehicle charging services do not qualify as utilities and therefore are not subject to regulation, under state code, as "public utilities." By adopting the Proposed Decision, the Commission also outlined its regulatory authority over services related to charging electric vehicles:

- "If a provider of electric vehicles charging services procures electricity on the wholesale market the Commission has jurisdiction to enforce procurement requirements and other laws and rules that apply to direct transactions including Pub. Util. Code § 365.1."

- "Pub. Util. Code § 740.2 grants the Commission specific authority to implement rules necessary to facilitate the widespread deployment of electric vehicles in California."

- "If an electric vehicle service provider receives electricity over a utility's transmission and distribution system, the Commission has authority to dictate the terms under which the utility will provide service to the provider."

- "If an electric vehicle service provider is a bundled customer of an investor-owned utility, the Commission can set all components of the retail rate paid by the provider."

- "If an electric vehicle service provider is a customer of an electricity service provider or community choice aggregator, the Commission can set all components of the retail rate paid by the provider except for the generation component."

- "Pub. Util. Code § 8362(a) directs the Commission to adopt standards and protocols to ensure functionality and interoperability developed by public and private entities."

- "The sale of electricity by an investor-owned utility to an electric vehicle service provider is a retail sale of electricity, not a wholesale sale or a 'sale for resale.'"

The proceeding then went into Phase 2, during which the Commission "will further address policies to overcome barriers to the widespread use of electric vehicles."

August 2010: Commission issued a Ruling soliciting comments on Commission Staff paper entitled, "The Utility Role in Supporting Plug-In Electric Vehicle Charging."

September 2010: Comments due.

October 2010: Commission issued a Ruling soliciting comments due November 2010 and reply comments due December 2010. Comments to answer questions related to the following:

- Separate Meter Costs
- Submetering Protocol
- Utility Customer Education & Outreach
- Roadmap for Revisiting Rate Design
- Electric Vehicle Service Provider (EVSP) – Applicable Rate
- Schedules
- Smart Grid Overlap Issues – Schedule Modification

December 2010: Commission issued a Ruling entering four Staff documents into the record:

- "Energy Division Issues Paper: The Utility Role in Supporting Plug-in Electric Vehicle Charging – December 2010 (Revised) Version"

- "Energy Division Workshop Report: The Utility Role to Support Plug-in Electric Vehicles Workshop – September 27, 2010"

- "Energy Division Issues Paper: Revenue Allocation and Rate Design: Facilitating Plug-in Electric Vehicle Integration – December 2010 (Revised) Version"

- Energy Division Workshop Report: Revenue Allocation and Rate Design Workshops – September 29 and 30, 2010"

March 2011: Commission issued a Proposed Decision that, if approved, would facilitate the adoption and use of plug-in hybrid and electric vehicles. Specifically, the Proposed Decision recommended:

- PG&E, SDG&E, and SCE "shall (1) collaborate with stakeholders to further develop a plug-in hybrid and electric vehicle data clearinghouse proposal, including feasibility analyses, to track the location and re-location of plug-in hybrid and electric vehicles charging on the electric grid, (2) work with the Department of Motor Vehicles and other relevant government agencies to determine what data can legally be made available to the data clearinghouse or to the utilities directly consistent with all applicable privacy laws, (3) ensure entities other than utilities pay a fair share of all costs related to the development of the data clearinghouse, including initial feasibility studies and implementation costs, and (4) jointly file a report in this proceeding within 120 days of the effective date of this decision."

- PG&E "shall file a plug-in hybrid and electric vehicles rate design proposals in the rate design phase of its 2014 General Rate Case." SDG&E and SCE "shall file plug-in hybrid and electric vehicles rate design proposals in Rate Design Window applications in 2013 as provided for and in accordance with the schedule in Decision 89-01-040. These plug-in hybrid and electric vehicles rate design proposals shall include an analysis of plug-in hybrid and electric vehicles charging load profiles, the costs and benefits of plug-in hybrid and electric vehicle integration and charging, and how consumers respond to plug-in hybrid and electric vehicles time-of-use price differentials. These rate design proposals shall also include an evaluation of the feasibility and benefits of a plug-in hybrid and electric vehicles residential demand charge."

- PG&E, SDG&E, and SCE "shall form a working group to develop a plug-in hybrid and electric vehicle submeter protocol. . . . [PG&E, SDG&E, and SCE] shall include in the working group, at a minimum, Commission Staff, California Department of Food and Agriculture, automakers and electric vehicle service providers, hold at least one publicly noticed workshop, and issue a report following the workshop."

- "Between the effective date of this decision and June 30, 2013, all residential service facility upgrade costs in excess of the residential allowance shall be treated as common facility costs rather than being paid for by the individual plug-in hybrid and electric vehicle customer. This policy shall not apply in the non-residential context." PG&E, SDG&E, and SCE "shall propose a policy and procedural mechanism to address these residential upgrade costs in the January 1, 2013 reports regarding load research to be filed in this proceeding."

- PG&E, SDG&E, and SCE "shall jointly prepare a load research plan and undertake load research…" and file their research report in January 2013.

- "Each utility shall provide their customers with information regarding the choices available to the customer for charging a plug-in hybrid and electric vehicle consistent with the requirements in this Ordering Paragraph."

April 2011: Comments filed.

Commission Files Comments with FERC on Smart Grid Standards

March 2011: Commission Staff sought FERC's permission to file comments in its rulemaking proceeding on "smart grid interoperability standards and protocols for interstate commerce and wholesale electricity markets."

April 2011: After receiving FERC permission, Commission Staff filed its comments with FERC. The Staff's comments advance three main points:

1. The CPUC Supports the Overarching Goal of the NIST/FERC Effort

- "The CPUC supports the development of clear, high-level, consensus standards for the Smart Grid in order to avoid a mismatched national patchwork of standards that could hinder interoperability, innovation, and the reliability of interstate transmission of electricity and wholesale electricity markets."
- "While the CPUC has suggestions about ways in which the FERC and the NIST processes may provide additional benefits to this important national discussion, such input should not be construed as criticism of the NIST's work on this subject or its processes and efforts in general."
- "Thus, any standards and protocols eventually adopted by the FERC should provide stakeholders and regulators direction on implementation and should function as guidelines rather than necessarily being subject to FERC enforcement authority."
- "Due to the nascent stage of Smart Grid deployment and development at the retail and distribution level, local regulatory authorities may benefit by voluntary standards in the form of actionable requirements adopted by the FERC."

2. There is not Sufficient Consensus on the Five Sets of Smart Grid Standards to Adopt Them as Proposed

- "The CPUC recognizes and supports the opinions expressed by the majority of the panelists at the FERC Technical Conference that there is not sufficient consensus on the proposed standards. . . . This observation should not be interpreted as a criticism of the NIST's processes in general or the work it has produced on the instant subject thus far within a relatively short timeframe. . . . The FERC, however, should not proceed towards actively considering the adoption of the proposed Smart Grid standards until there is sufficient consensus on those standards. Rather, the CPUC suggests the FERC solicit the NIST to continue to work with stakeholders and other relevant grid reliability organizations . . . towards developing consensus positions using certain improvements to the stakeholder process."

- "Should the FERC determine that there is sufficient consensus regarding the proposed standards, the CPUC believes that the FERC's ordinary legal practices and procedures require full evidentiary, policy and legal analysis of the proposed standards and their analytical bases prior to either adoption of voluntary standards or implementation of any potential mandatory standards."

- "Additionally, the CPUC suggests that the FERC should take a more active role in the development of standards in the NIST process."

<u>3. Any Standards Adopted by the FERC Should Be Developed Through Transparent, Public, Inclusive and Collaborative Processes</u>

- "The CPUC would suggest the process for review of the initial five standards did not follow the process as explained to the CPUC or envisioned by the CPUC. Specifically, the stakeholder process developed by the NIST, via the Smart Grid Interoperability Panel (SGIP), did not provide an adequate review of the standards sent to FERC."

- "The process for review of standards at the NIST has been somewhat unclear. Although some NIST sub-groups were able to review the proposed standards, the CPUC understands that recommended changes were not addressed before the proposed standards were forwarded to the FERC."

- "More fundamentally, there seems to be confusion within and among the relevant agencies and stakeholders regarding whether or how the Smart Grid *framework* of standards developed by NIST will (or will not) translate in the *standards* discussed in the EISA and the instant FERC proceeding. Unless and until such confusion and disconnect are addressed, this process could lead to attempts to make a square peg fill a round hole."

- "The CPUC suggests that regulators and utilities, as entities responsible for implementing the Smart Grid, need a greater voice in the consideration of standards in the SGIP process."

2012 – 2014 IOU DR Applications

March 2011: IOU's filed their 2012 – 2014 applications for demand response.

March 2011: Commission issued a Ruling consolidating three separate cases—one for each IOU DR application—into one.

April 2011: Commission issued a Ruling incorporating "by reference" into the record of the proceeding a utility-sponsored report on permanent load shifting filed in Docket R07-01-041 in February 2011. The Ruling also incorporated the comments and reply comments filed about the report in March 2011. Furthermore, the Ruling directed PG&E, SDG&E, and SCE to "revise the discussions and proposals related to permanent load shifting contained in the 2012 – 2014 Demand Response applications filed on March 1, 2011 to conform to the guidelines and modifications contained in this ruling and shall file and serve revisions to the permanent load shifting portion of the 2012-2014 Demand Response applications within 21 days from the date of this ruling."

May 2011: Prehearing Conference.

May 2011: Commission issued a Scoping Ruling. The Ruling determined that:

- "The category of this proceeding is ratesetting. "
- "Hearings will be held."
- "Ex parte communications are restricted and subject to reporting requirements."
- The issues for this proceeding are:
  - o "compliance with any and all directives related to DR"

- “compliance with Resource Adequacy rules”
- “reasonableness of program and portfolio design, measured in terms of cost effectiveness, track record, future performance, cost, flexibility and versatility, adaptability, locational value, integration, consistency across the Joint Applicants’ applications, simplicity, recognition, environmental benefits, consistency with Commission policies and general policies affecting revenue allocation”
- “the evolving nature of DR and the impact of its evolution on these current and future applications”
- “the adequacy of the DR programs . . . whether existing and proposed programs and pilots are sufficient to meet California energy goals in light of the changing nature of the energy grid and the 33% renewable requirement”
- “PLS cost-effectiveness, CAISO market integration, aggregator-utility contracts, and DR market competition”
- “continuous coordination of DR programs with other Commission and State agencies’ energy policies and programs including the California Energy Action Plan and the California Long Term Energy Efficiency Strategic Plan”

- “The Joint Applicants shall revise their cost effectiveness analyses and load impact estimates for all demand response programs 1) using the data from the April 1, 2011 Load Impact Reports and 2) using the data from the April 1, 2011 Load Impact Reports and the inputs from Attachment 1. The Joint Applicants shall serve both sets of revisions not later than May 27, 2011.”
- Schedule adopted:
  - 5/ 20/11: Revisions to Cost Effectiveness Analyses Related to Permanent Load Shifting Activities Served
  - 5/27/11: Revisions to Cost Effectiveness Analyses and Load Impact Estimates 1) using April 1, 2011 Load Impact Report Data and 2) using both the April 1, 2011 Load Impact Report Data and the Responses to Attachment 1 Served
  - 6/13/11: Testimony Served

- o <u>7/11/11</u>: Rebuttal Served
- o <u>7/19 – 7/22/11</u>: Evidentiary Hearings
- o <u>8/19/11</u>: Opening Briefs/Comments Filed
- o <u>9/9/11</u>: Reply Briefs/Comments Filed
- o <u>10/28/11</u>: Proposed Decision Issued
- o <u>12/1/11</u>: Proposed Decision on Commission Agenda

<u>California Energy Commission Study on DR & Lighting Technology</u>

<u>March 2011</u>: California Energy Commission published a report, "Lighting California's Future: Cost-Effective Demand Response," reviewing a project it undertook with the assistance of the California Lighting Technology Center that aimed "to introduce a novel demand response lighting control technology that can easily be retrofitted to existing buildings." As the CEC report explains, "The new system would be capable of receiving a utility demand reduction signal and transmitting, over the building power lines, a load-shed signal to multiple receiver devices."

<u>California Energy Commission Report on DR & Commercial-Building Lighting</u>

<u>March 2011</u>: California Energy Commission published a report, "Lighting California's Future: Integration of Lighting Controls with Utility Demand Response Signals," reviewing a project it undertook with the assistance of Southern California Edison (SCE) and the California Lighting Technology Center (CLTC) "to develop, test, and demonstrate lighting control systems that automatically respond to California utility demand response signals." The project in question tested three lighting systems under four demand response scenarios: "right now, next hour, later same day, and next day."

LEGISLATIVE:

<u>Energy-Storage Portfolio Standard</u>

<u>February 2010</u>: Bill introduced in the California State Assembly that would establishe an energy-storage portfolio standard

August 2010: California State Assembly passed the bill, thereby adopting the State Senate’s amendments to it.

September 2010: Governor Schwarzenegger signed the legislation. The new law includes the following provisions:

- The California Public Utilities Commission is required, by March 1, 2012, "to open a proceeding to determine appropriate targets, if any, for each load-serving entity to procure viable and cost-effective energy storage systems and, by October 1, 2013, to adopt an energy storage system procurement target, if determined to be appropriate, to be achieved by each load-serving entity by December 31, 2015, and a 2nd target to be achieved by December 31, 2020."

- The governing boards of local publicly-owned utilities are required, by March 1, 2012, "to open a proceeding to determine appropriate targets, if any, for the utility to procure viable and cost-effective energy storage systems and, by October 1, 2014, to adopt an energy storage system procurement target, if determined to be appropriate, to be achieved by the utility by December 31, 2016, and a 2nd target to be achieved by December 31, 2021."

- An "electrical corporation that has 60,000 or fewer customers within California and a public utility district that receives all of its electricity pursuant to a preference right adopted and authorized by the United States Congress pursuant to a specified law" are exempt from these requirements.

- Load-serving entities are to file a report with the Commission "demonstrating that it has complied with the energy storage system procurement targets and policies" adopted by the Commission in January 2016 and January 2021.

- Local publicly-owned utilities are to file a report with the Energy Commission "demonstrating that it has complied with the energy storage system procurement targets and policies adopted by the governing board" in January 2017 and January 2022.

Protecting Consumer Data Collected by Smart Meters

September 2010: Governor Schwarzenegger signed legislation establishing rules protecting energy-consumption data “that is made available as part of an advanced metering infrastructure.” The requirements for “electrical corporations" and "local publicly owned" utilities are "nearly identical." Key provisions of the bill are:

- A prohibition of utilities "sharing, disclosing, or otherwise making accessible to any 3rd party a customer's electrical or gas consumption data, as defined, except as specified."

- A requirement that utilities "use reasonable security procedures and practices to protect a customer's unencrypted electrical and gas consumption data from unauthorized access, destruction, use, modification, or disclosure."

- A prohibition of utilities "selling a customer's electrical or gas consumption data or any other personally identifiable information for any purpose."

- A prohibition of utilities "providing an incentive or discount to a customer for accessing the customer's electrical or gas consumption data without the prior consent of the customers."

- A requirement that utilities use "an advanced metering infrastructure that allows a customer to access the customer's electrical and gas consumption data to ensure that the customer has an option to access that data without being required to agree to the sharing of his or her personally identifiable information with a 3rd party."

- A requirement that a 3rd party, which is contracted by a utility "for a service that allows a customer to monitor his or her electricity or gas usage" and which "uses the data for a secondary commercial purpose," disclose "that secondary commercial purpose to the customer."

Smart Meter Opt-Out

December 2010: Bill introduced into General Assembly that would mandate that the California Public Utilities Commission allow utility customers to decline the installation of smart meters. It also would require the Commission to direct utilities to offer "alternative options" to such customers. The bill would direct the Commission to disclose more information about smart metering technology and to call on utilities to suspend deployments until complete compliance with the aforementioned stipulations.

January 2011: Bill referred to Utility and Commerce Committee.

RPS: 33% by 2020

March 2011: The California State Assembly approved a bill that would increase the state's renewable energy portfolio standard.

April 2011: Governor Jerry Brown signed the bill. The enacted legislation requires load-serving entities to procure by 2020 renewable energy in the amount of 33% of total retail sales. Interim RPS goals are 20% by 2013 and 25% by 2016. The new law provides an exemption, however, for compliance delays due to transmission problems and other issues. The previous RPS in California, which was set in 2002 and accelerated in 2006, was 20% by 2020.

Colorado

REGULATORY:

Smart Grid Data Privacy

November 2010: Commission issued a Notice of Proposed Rulemaking regarding smart grid data privacy. The NOPR, which floats seven rule changes, "makes certain findings and introduces proposed Smart Meter data privacy and disclosure rules in large part based on input provided by interested parties in Docket Nos. 09I-593EG and 10I-099EG." Those proceedings led the Commission to conclude that "added protections for personal information are essential in order to protect customer privacy" and that "an effective privacy policy needs to be thoughtful and pro-active rather than just-in-time and reactive."

January 2011: Hearing. Comments and reply comments were filed prior to it.

February 2011: Commission facilitated a discussion about "the progress made in assembling the consensual rules."

January, February, and March 2011: An informal working group held a series of workshops. From these workshops, the Public Service Company of Colorado produced a "strawman" document. The strawman, according to the utility, “reflects a great degree of consensus.” Not all of its provisions, however, have the unanimous support of the workshop participants. As a result, Public Service Company of Colorado sees portions of the strawman as “as placeholders for future comments” from parties to the proceeding. Provisions of the strawman include:

- “A utility shall provide to a customer and to any third-party recipient to whom the customer has authorized disclosure of the customer’s CD, access to the customer’s CD in electronic machine-readable form,
- “A utility may disclose CD to a third–party entity, including an affiliate, who has been contracted to assist the utility in the provision of regulated utility services or in the aggregation of CD,
- “Except as outlined in Rules 3011(e), 3014(a) and 3016(f), a utility shall not disclose CD to any third-party unless the customer or a third–party acting on behalf of a customer submits a written or electronic signed Consent Form that has been executed by the customer of record.”

April 2011: Hearing focused on “proposed rules and related matters.” Comments and reply comments were filed prior to the hearing.

April 2011: Through an Order, the Commission solicited comments on two additional sets of questions—one set from the proceeding’s ALJ and one set from the Office of Consumer Counsel.

April 2011: Comments due.

May 2011: Hearing.

May 2011: “Final written comments” due.

June 2011: Cybersecurity workshop featuring officials from the DOE and NIST discussing NIST's identification of cybersecurity standards and FERC's current consideration of them. The Commission's co-hosts were the Governor's Energy Office, the Center for International Security, Policy and Research (CISPR), and the Colorado Division of Emergency Management.

Colorado Smart Grid Task Force

July 2010: The Colorado Smart Grid Task Force (SGTF) was created through legislation signed by Governor Ritter in June 2010. The SGTF was tasked with providing "technical expertise and strategic policy recommendations, from a statewide perspective, to the public utilities, the [Colorado Public Utilities] Commission, and the General Assembly."

January 2011: SGTF presented its final report to Governor Bill Ritter, the Colorado General Assembly, and the Colorado Public Utilities Commission. The report, "Deploying Smart Grid in Colorado: Recommendations and Options," reflects the SGTF's six months of work since its legislative inception. The report presents a "body of consensus recommendations" within six topic areas: (1) Challenges and Opportunities in Colorado; (2) Workforce and Economic Development; (3) Consumer Issues and Data Management; (4) Distributed Energy Resources and Grid Management; (5) Technical Specifications; and (6) Grid Operations. The SGTF report also presents "three distinct scenarios" for transitioning to a "flexible, secure, and reliable smart grid"—(1) Incremental Approach, (2) Moderate Approach, and (3) Transformational Approach.

LEGISLATIVE:

Smart Grid Legislation

March 2010: Bill introduced that would create the Colorado Smart Grid Task Force, responsible for providing "technical expertise and strategic policy recommendations, from a statewide perspective, to the public utilities, the [Colorado Public Utilities] Commission, and the General Assembly."

June 2010: Governor Ritter signed legislation. The main goal of the Colorado Smart Grid Task Force is to develop by January 2011 a report for the governor, Commission, and General Assembly that contains "recommendations and analysis on the feasibility, cost, and timing of transitioning to a secure, resilient, and technologically advanced electric grid." The Smart Grid Task Force is to meet annually thereafter to consider updates to the "2011 Colorado Smart Grid Report." This report is to address:

Issues Related to the Utility Side of the Meter

- Grid Reliability
- Grid Efficiency
- Outage Restoration and Recovery
- Distributed Generation Integration
- Transportation Electrification
- System Integration of Renewable and Conventional Sources of Electric Power Generation

<u>Issues Related to the Customer Side of the Meter</u>

- Consumer Metering Protocols
- Driving Increases in Consumer Efficiency
- Providing Effective Consumer Information
- Integration of Demand Response Programs
- Integration of Variable Pricing Mechanisms

<u>Potential Impacts from the Development of the Smart Grid</u>

- Consumer Protection and Privacy
- Cybersecurity
- Communication and Technical Standards
- Workforce and Economic Development Issues
- Energy Efficiency and Demand Response
- Emissions from Electric Generation.

<u>January 2011</u>: Colorado Smart Grid Task Force published its report, "Deploying Smart Grid in Colorado: Recommendations and Options," thereby complying with the law passed in June 2010.

Connecticut

REGULATORY:

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

LEGISLATIVE:

<u>DR Policy and "Department of Energy and Environmental Protection"</u>

<u>January 2011</u>: Omnibus energy bill introduced in the General Assembly that, among other things, would encourage renewable energy, energy efficiency and demand response; strengthen state oversight of utilities' power procurement; and create the "Department of Energy and Environmental Protection," an agency to succeed the Department of Environmental Protection and the Department of Public Utility Control.

June 2011: Bill passed Connecticut Senate and House.

June 2011: Governor Malloy signed the legislation. Its provisions related to demand response—including peak demand reduction and TOU pricing—are:

Sec. 39. Section 16a-3b of the general statutes is repealed and the following is substituted in lieu thereof (*Effective July 1, 2011*):

(a) The Public Utilities Regulatory Authority shall oversee the implementation of the integrated resources plan approved by the Commissioner of Energy and Environmental Protection pursuant to section 16a-3a, as amended by this act. 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 plan through the comprehensive conservation and load management plan prepared pursuant to section 16-245m, as amended by this act, 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 plan.

Sec. 61. Section 22a-174*l* of the general statutes is repealed and the following is substituted in lieu thereof (*Effective July 1, 2011*):

(b) When issuing or renewing the general permit [for constructing and operating emergency engines and distributed generation resources] pursuant to this section, the Commissioner of Energy and Environmental Protection shall consider energy generation that will maximize the savings to the state's electric ratepayers and benefit the state's economy as a whole, but shall ensure that any emission increases resulting from the operation of sources covered by the general permit are offset by emission decreases from sources in Connecticut consistent with Connecticut's air quality attainment planning needs and requirements. The sources of decreases in emissions may include, but not be limited to, electric generation sources and demand response.

Sec. 89. Section 16a-3a of the general statutes is repealed and the following is substituted in lieu thereof (*Effective July 1, 2011*):

(a) The Department of Energy and Environmental Protection, in consultation with the Connecticut Energy Advisory Board and the electric distribution companies, shall review the state's energy and capacity resource assessment and develop an integrated resources plan for the procurement of energy resources, including, but not limited to, conventional and renewable generating facilities, energy efficiency, load management, demand response, combined heat and power facilities, distributed generation and other emerging energy technologies to meet the projected requirements of their customers in a manner that minimizes the cost of such resources to customers over time and maximizes consumer benefits consistent with the state's environmental goals and standards. Such integrated resources plan shall seek to lower the cost of electricity.

(b) On or before January 1, 2012, and biennially thereafter, the Department of Energy and Environmental Protection, in consultation with the Connecticut Energy Advisory Board and the electric distribution companies, shall prepare an assessment of (1) the energy and capacity requirements of customers for the next three, five and ten years, (2) the manner of how best to eliminate growth in electric demand, (3) how best to level electric demand in the state by reducing peak demand and shifting demand to off-peak periods. . .

(c) Resource needs shall first be met through all available energy efficiency and demand reduction resources that are cost-effective, reliable and feasible. The projected customer cost impact of any demand-side resources considered pursuant to this subsection shall be reviewed on an equitable bases with non-demand-side resources. The integrated resources plan shall specify (1) the total amount of energy and capacity resources needed to meet the requirements of all customers, (2) the extent to which demand-side measures, including efficiency, conservation, demand response and load management can cost-effectively meet these needs in a manner that ensures equity in benefits and cost reduction to all classes and subclasses of consumers, (3) needs for generating capacity and transmission and distribution improvements, (4) how the development of such resources will reduce and stabilize the costs of electricity to each class and subclass of consumers, and (5) the manner in which each of the proposed resources should be procured, including the optimal contract periods for various resources.

Sec. 104. Subsection (g) of section 16-245 of the general statutes is repealed and the following is substituted in lieu thereof (*Effective July 1, 2011*):

(g) As conditions of continued licensure, in addition to the requirements of subsection (c) of this section . . . (12) the licensee shall offer a time-of-use price option to customers. Such option shall include a two-part price that is designed to achieve an overall minimization of customer bills by encouraging the reduction of consumption during the most energy intense hours of the day. The licensee shall file its time-of-use rates with the Public Utilities Regulatory Authority. . . .

Sec. 105. (NEW) (*Effective July 1, 2011*): The Department of Energy and Environmental Protection shall require each electric distribution company to notify its customers on an ongoing basis regarding the availability of time-of-use meters, if applicable.

Delaware

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

District of Columbia

REGULATORY:

PowerCentsDC

Background: PowerCentsDC program concluded October 2009. PowerCentsDC was a two-year pilot program in Washington, DC, through which nearly 900 of Pepco's residential customers tested smart meters and smart thermostats as well as one of three pricing options: (1) Hourly Pricing; (2) Critical Peak Pricing; or (3) Critical Peak Rebate. It began in 2007 with customer recruitment. Participants were on the “smart prices” from July 2008 through October 2009. All participants received smart meters, while a control group of 400 randomly-selected customers not participating in the program also received a smart meter. Participating customers with central AC received a smart thermostat with direct-load-control functionalities and a real-time price display. PowerCentsDC was overseen by the Smart Meter Pilot Program, Inc.—comprising Pepco, the DC Public Service Commission, the DC Consumer Utility Board, International Brotherhood of Electrical Workers (IBEW) Local 1900, and the DC Office of the People's Counsel—and was managed by a smart grid consulting firm.

September 2010: The final evaluation of the PowerCents DC Program was published. The analysis, "PowerCentsDC Program: Final Report," weighs the many factors of the pilot, including the types of customers who participated; their response to smart meters and smart thermostats; and their demand reduction relative to Critical Peak Pricing, Critical Peak Rebate, or Hourly Pricing. Specific results include:

Peak Reduction by Pricing Plan and Customer Type

- CPP: 34% peak-demand reduction in summer; 13% peak-demand reduction in winter

- CPR: 13% peak-demand reduction in summer; 5% peak-demand reduction in winter

- HP: 4% peak-demand reduction in summer; 2% peak-demand reduction in winter

Low-Income Customers

- Low-income customers only participated in CPR plan

- Relative to CPR, low-income customers reduced peak demand 11% and regular-income customers reduced it by 13%

Effects of Temperature

- CPP: 26% peak-demand reduction at 85˚F; 43% peak-demand reduction at 97˚F

- CPR: 8% peak-demand reduction at 85˚F; 20% peak-demand reduction at 97˚F

- HP: 3% peak-demand reduction at 85˚F; 3% peak-demand reduction at 97˚F

With Smart Thermostats—Summer

Regular Customer

- CPP: 49% peak-demand reduction
- CPR: 17% peak-demand reduction
- HP: 10% peak-demand reduction

All Electric Customer

- CPP: 51% peak-demand reduction
- CPR: 24% peak-demand reduction
- HP: -2% peak-demand reduction

No Smart Thermostats—Summer

Regular Customer

- CPP: 29% peak-demand reduction
- CPR: 11% peak-demand reduction
- HP: results not statistically valid at 90% level

All Electric Customer

- CPP: 22% peak-demand reduction
- CPR: 6% peak-demand reduction
- HP: 10% peak-demand reduction

Customer Bill Impacts

- CPP
  - Average Monthly Bill Standard Offer Service: $101.26
  - Average Monthly Bill PowerCentsDC: $99.70
  - Dollar Savings: $1.56
  - Percent Savings: 2%

- CPR
  - Average Monthly Bill Standard Offer Service: $99.66
  - Average Monthly Bill PowerCentsDC: $95.07
  - Dollar Savings: $4.59
  - Percent Savings: 5%

- HP
  - Average Monthly Bill Standard Offer Service: $110.44
  - Average Monthly Bill PowerCentsDC: $77.42
  - Dollar Savings: $43.02
  - Percent Savings: 39%

- “Over 91% of CPP and CPR participants paid less on the smart prices, with 80% having bills between 10% less and 0% less on PowerCentsDC prices. All HP participants saved on the program.”

<u>Customer Feedback</u>

- “Over 74% of participants were satisfied with the program, and only 6% were dissatisfied”

- “Over 93% of participants who expressed a preference preferred PowerCentsDC pricing over Pepco’s default Standard Offer Service pricing”

- “About 89% of participants would recommend PowerCentsDC to their friends and family”

- “The main motivation for participation was saving money (73%), followed by reducing emissions (34%), exploring Smart Grids (33%), and assisting policymakers (32%)”

- “Participants’ most common peak demand reduction measures was avoiding use of appliances (60%), with nearly as many reducing air conditioning consumption (59%).”

The evaluation concludes with the following findings:

- “Consistent with other pilots, PowerCentsDC showed that consumers reduced summer peak usage in response to dynamic prices, energy information, and automated control”

- “CPP prices led to the greatest peak demand reductions”

- “CPR prices were most popular”

- “Customers with limited-income . . . signed up at higher rates than others, reduced peak very slightly less than others, and saved money on the program”

- “Summer peak reductions were greater than winter, implying more discretionary load”

- “Automated response via smart thermostats increased the reduction”

- "The vast majority of participants saved money, even with revenue neutral prices."

LEGISLATIVE:

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

Florida

REGULATORY:

Utilities' DSM Plans in Compliance with State Law

March 2010: Utilities subject to the Florida Energy Efficiency and Conservation Act (FEECA) filed their 2010 – 2019 DSM plans. This law requires the Commission to set annual goals for peak demand and electricity consumption. It also requires utilities to file DSM plans with the Commission.

September – October 2010: Commission issued a series of Orders in which it accept or denied the DSM plans filed:

Orlando Utilities Commission

- Approved
- No DR in DSM plan

Progress Energy Florida

- Not completely approved. Refile within 30 days.
- DSM plan includes Direct Load Control and TOU pricing

Tampa Electric Company

- Not completely approved. Refile within 30 days.
- DSM plan includes Residential Price Responsive Load Management, Commercial Load Management, Commercial Demand Response, and Industrial Load Management

Florida Public Utilities Company

- Decision Deferred
- No DR in DSM plan

JEA

- Approved
- No DR in DSM Plan

Florida Power & Light

- Decision Deferred
- Residential Load Management
- Commercial and Industrial Load Control

Gulf Power Company

- Not completely approved. Refile within 30 days.
- DSM plan includes RTP

November 2010: Tampa Electric filed revised DSM Plan.

January 2011: Order approving Tampa Electric Company's revised DSM Plan.

LEGISLATIVE:

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

Georgia

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

Hawaii

REGULATORY:

Hawaii EEPS Proceeding

March 2010: Commission initiated proceeding to examine the creation of energy-efficiency portfolio standards (EEPS) pursuant to state law passed in 2009.

May 2011: Commission issued a Procedural Order identified the proceeding's next steps.

May 2011: Technical Session.

June 2011: Commission issued a Procedural Order revising the proceeding's next steps:

- 8/5/11: Draft Report and Proposed Straw Framework of Commission's Consultant Transmitted to Parties for Review and Comment in their Final Statements of Position.
- 8/12/11: Follow-up Technical Session.
- 8/29/11: Parties' Final Statements of Position.
- 9/12/11: Final Report and Proposed Straw Framework of Commission's Consultant Transmitted to Parties
- 10/3/11: Pre-hearing Conference
- 10/10/11: Panel Hearing (if necessary)
- 3 Weeks after Transcripts Filed: Open Briefs
- 2 Weeks after Opening Briefs are Filed: Reply Briefs.

LEGISLATIVE:

No legislative 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:

Illinois Statewide Smart Grid Collaborative (ISSGC)

Background: The Illinois Statewide Smart Grid Collaborative (ISSGC) was formed by ComEd and Ameren in compliance with a September 2008 Order from the Commission. Collaborative participants, in addition to the utilities, included Commission Staff, consumer advocates, government agencies, unions, business groups, technology companies, RTOs, and academic institutions.

August 2010: The ISSGC held its final workshop.

October 2010: The ISSGC filed its "Collaborative Report," containing the group's recommendations, with the Illinois Commerce Commission. The report summarizes the ISSGC's work to address thirteen "foundational policies" while undertaking seven tasks. The report's chapters reflect six of these tasks (with the seventh task being the report itself):

- Smart Grid Definition
- Smart Grid Applications
- Consumer Policy Issues
  - Data Privacy and Data Access
  - Competitive Retail Market Structure
  - Remote Connection and Disconnection
  - Customer Prepayment for Service

- Utility Rates in a Smart Grid Environment
  - Smart Grid Consumer Education
  - Recovery of Utility Smart Grid Costs
  - Statutory Energy Goals and Smart Grid

- Technical Characteristics and Requirements

- Cost-Benefit Framework

- Utility Filing Requirements.

2011 Power Procurement Plan

August 2010: The Illinois Power Agency (IPA), which was created in 2008 in compliance with a 2007 state law, filed with the Illinois Commerce Commission its 2011 "Draft Power Procurement Plan" for Ameren and ComEd. The draft describes a proposed procurement strategy for the five-year period between June 2011 and May 2016. This year, for the first time, the IPA is proposing that demand response be included as an eligible product in the procurement process for energy, capacity, and renewable energy resources.

August 2010: Workshops.

September 2010: Comments due.

September 2010: "The IPA has fourteen days following the end of the 30-day review period to revise the Draft Procurement Plan, as necessary, based on the comments and to file the final Plan with the Commission for posting on its website."

October 2010: "Following the submission of this Plan, within five days, any person objecting to the Plan may file an objection with the Commission."

December 2010: Commission issued a Final Order approving a modified version of the 2011 Power Procurement Plan. The Commission determined that demand response "will not be treated as energy supply resources as proposed by the IPA." The reason for this decision is based on the Commission's doubt about cost-effectiveness and about the effectiveness of reducing capacity. The Commission, however, "strongly encourages the IPA to better support its arguments [for demand response] in future proceedings, rather than just repeating previously rejected arguments."

PHEV Initiative

September 2010: Commission created the Plug-In Vehicle Initiative as an effort to prepare the state's electric grid and natural gas distribution network for the mass adoption of electric vehicles and natural gas vehicles. The goals of the group are:

- Determining the impact of the initial deployment of Plug-in Electric Vehicles (PEVs) on the State's electric grid
- Determining potential/future regulatory considerations necessary to accommodate PEVs
- Establishing consistent statewide policies for managing PEV infrastructure and use
- Generating accelerated interest by auto manufacturers for introduction of PEVs into Illinois markets
- Crafting consumer education and outreach information components.

December 2010: Commission received initial assessments of the "impact of the first wave of plug-in vehicle deployments" from the state's three IOUs.

January 2011: Comments on assessments due.

Illinois Energy Plan

May 2011: Governor Pat Quinn issued the state's "Comprehensive Energy Strategy." The plan is to be effected by modernizing the state's regulatory framework and by supporting several pieces of legislation. Regarding smart grid regulations, the plan calls for the following changes to the Illinois Public Utilities Act:

- "Allow consumers with smart meters to choose effective, real time pricing to save on energy bills."
- "Define Smart Grid investments and ensure consumer privacy and that data from Smart Grid will benefit consumers. The Governor's plan guarantees that consumers, not JUST the utility companies, benefit from any electric grid upgrades by defining the kinds of upgrades that will benefit consumers and ensure job creation."

- “Allow the energy efficiency portfolio to cover larger improvements. Current law requires a tight timetable for projects that hinders large improvements such as new construction and major overhauls of building systems.”

LEGISLATIVE:

Spending Caps on DR Used to Meet Demand-Reduction Standard

February 2011: Legislation introduced into General Assembly that would amend law enacted by Governor Blagojevich in 2007 that mandates utilities to reduce peak demand by 0.1% over the prior year, for ten years, by implementing cost-effective demand response programs. The bill being considered would curb the cost to customers for implementing efficiency and demand response programs. Specifically, customers’ bills could not increase more than 2.015% of the amount paid per KWh in 2007 or “the incremental amount per kilowatthour paid for these measures in 2011.”

March 2011: Bill amended by House Committee Amendment 1.

May 2011: Bill amended by House Committee Amendment 2. One section of the amended bill reads:

> “Thereafter [2011], the amount of energy efficiency and demand-response measures implemented for any single year shall be reduced by an amount necessary to limit the estimated average net increase due to the cost of these measures included in the amounts paid by eligible retail customers in connection with electric service to no more than the greater of 2.015% of the amount paid per kilowatthour by those customers during the year ending May 31, 2007 or the incremental amount per kilowatthour paid for these measures in 2011, unless the Commission concludes, based on evidence presented during a plan filing proceeding under subsection (f) of this Section, that the limitation would result in the utility foregoing cost-effective opportunities for savings that would otherwise create net aggregate bill reductions for its customers; if the Commission so concludes, then it may direct the utility to exceed the spending limits in this subsection (d) only to the extent necessary to achieve the savings targets in subsection (b) of this Section.”

Energy Infrastructure Modernization Act

December 2010: Bill introduced in Illinois House that would create a policy framework and would reform regulation so as to facilitate grid modernization efforts.

February 2011: Bill introduced in Illinois Senate that would facilitate smart grid investments and direct utilities to create plans for demand response and AMI.

Spring 2011: House and Senate bills merged.

May 2011: House passed the bill.

May 2011: Senate concurred with three House amendments to the bill and sent engrossed version of it to Governor Pat Quinn. Governor Quinn was cited in several news reports as threatening to veto bill. At this point, the bill has four sections dealing with the smart grid. These sections would mandate:

- That electric utilities "file an energy efficiency and demand-response plan with the Commission to meet the energy efficiency and demand-response standards for 2011 through 2013."

- That electric or gas utilities "may voluntarily elect and commit to undertake" an infrastructure investment program and that they may "recover the expenditures made under the infrastructure investment program through the ratemaking process…."

- That electric utilities "file a Smart Grid Advanced Metering Infrastructure Deployment Plan with the Commission…within 180 days after the effective date of the amendatory Act or by November 1, whichever is later, or in the case of a combination utility, by April 1, 2012."

- That electric utilities, within 180 days after the effective date of the bill, "create or otherwise designate a Smart Grid test bed, which may be located at one or more places within the utility's system, for the purposes of allowing for the testing of Smart Grid technologies."

Indiana

REGULATORY:

<u>End-Use Customer Participation in MISO and PJM</u>

<u>September 2008</u>: Commission initiated a proceeding to investigate end-use customer participation in the demand response programs of Midwest ISO and PJM.

<u>October 2008</u>: Commission held a preliminary hearing and prehearing conference to set the proceeding's schedule.

<u>February 2009</u>: Commission issued an 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."

<u>June 2009</u>: Parties to the proceeding filed Proposed Orders.

<u>July 2010</u>: Commission issued an Order declaring that end-use customers may not participate directly in RTO demand response programs or through third-party service providers/aggregators. They may participate in the RTO programs, however, through the load-serving entity that serves them. The Commission said RTO demand response programs "must work in tandem with, and not in contravention of, Indiana's utility regulatory framework." As a result, each Indiana utility must file with the Commission within 90 days tariffs or riders that authorize its retail customers' participation, though its own auspices, in PJM's or MISO's demand response programs. Furthermore, each utility must file with the Commission an annual report regarding this activity.

<u>September 2010</u>: Prehearing and Technical Conference.

<u>December 2010</u>: Commission opened two subdockets—one for PJM and one for MISO—and a series of subdockets within each of them to consider the filings made by utilities in December 2010 per the July 2010 Order. The Commission dedicated a new subdocket within the MISO or PJM subdocket for each utility's filings.

<u>PJM Subdocket</u>

Indiana Michigan Power Company (I&M)

October 2010: Indiana Michigan Power Company made its prescribed filing. Later, it joined the Indiana Office of the Utility Consumer Counselor (OUCC), the Indiana Industrial Group, and CPower in filing a Stipulation and Agreement on Procedural Matters and Request for Commission Approval.

November 2010: Commission set procedural schedule.

November 2010: Comments due on Rider D.R.S. 1 (Demand Response Service - Emergency).

November 2010: I&M filed replies to comments and filed Proposed Order.

December 2010: Exceptions to Proposed Order due.

December 2010: I&M filed reply brief.

January 2011: I&M filed "a proposed date for the filing of a proposed order regarding the ancillary service phase of this subdocket together with a procedural schedule for the balance of this phase of the subdocket."

February 2011: Evidentiary Hearing.

February 2011: I&M prefiled testimony and exhibits constituting its case-in-chief in support of Rider D.R.S. 2.

March 2011: OUCC and intervenors prefiled testimony and exhibits constituting their respective cases-in-chief.

March 2011: I&M prefiled testimony and exhibits constituting its rebuttal evidence.

April 2011: Evidentiary Hearing.

April 2011: I&M filed a Proposed Order.

April 2011: Commission issued an Order accepting the utility's Demand Response Service-Emergency Rider and directing the utility to file, by October 2012, a report that describes:

- how often the emergency demand response offers were called upon

- how the load reductions were measured or documented, and issues with customers meeting their commitments and whether this improved as customers gained experience
- the number of aggregators, the number of customers being served by the aggregators, the types of customers being served by aggregators, and how this compares to those customers participating directly with the utility.

May 2011: OUCC and intervenors filed their respective Exceptions and Comments to I&M's Proposed Order.

May 2011: I&M filed its Reply in support of its Proposed Order.

May 2011: Order approving I&M's Proposed Rider D .R.S. 2 and directing the utility to file its report with the Commission by May 2012.

MISO Subdocket

Northern Indiana Public Service

February 2011: Commission set procedural schedule.

February 2011: Comments due that respond "to the initial tariff filings"; testimony due supporting proposed tariffs; and Proposed Orders due.

February 2011: Hearing.

March 2011: "Deadline for interested customers to file with Midwest ISO concerning participating in demand response."

March 2011: Commission issued an Order that did the following:

- Approved: "NIPSCO's proposed DRR-l Rider, proposed DRR-l Service Agreement for Participating Customers and Proposed DRR-l Service Agreement for ARCs"

- Approved: "NIPSCO's proposed EDR-1 Rider, proposed EDR-1 Service Agreement for Participating Customers and Proposed EDR-1 Service Agreement for ARCs"

- Directed the utility to report by 10/31/12 on its "experience with the tariff and outlining the costs and expenses associated with the tariff and the administrative charges collected."

Indianapolis Power & Light Company

February 2011: Commission set procedural schedule.

February 2011: Comments due that respond "to the initial tariff filings"; testimony due supporting proposed tariffs; and Proposed Orders due.

February 2011: Hearing.

March 2011: "Deadline for interested customers to file with Midwest ISO concerning participating in demand response."

March 2011: Commission issued an Order that did the following:

- Approved: IPL's Proposed Rider 23, which "enables participation in MISO's Emergency Demand Response ('EDR') and economic energy Demand Response Resource Type 1 ('DRR-1') programs."

- Approved: IPL's "proposed Emergency Demand Response Agreement and Demand Response Resource Type 1 Agreement"

- Directed the utility to report by 10/31/12 on its "experience with the tariff and outlining the costs and expenses associated with the tariff and the administrative charges collected."

Duke Energy Indiana

February 2011: Commission set procedural schedule.

February 2011: Comments due that respond "to the initial tariff filings"; testimony due supporting proposed tariffs; and Proposed Orders due.

February 2011: Hearing.

March 2011: "Deadline for interested customers to file with Midwest ISO concerning participating in demand response."

March 2011: Order that did the following:

- Approved: Duke Energy Indiana's "Market Based Demand Response Rider, Standard Contract Rider No. 22," which provides "customers an option to participate in the MISO Ancillary Services Market ('ASM') as a demand response resource." Furthermore, "Rider

MBDR enables participation in MISO's Emergency Demand Response ('EDR') and Demand Response Resource Type 1 ('DRR-1') programs."

- Approved: "Duke Energy Indiana's proposed service agreements"
- Directed the utility to report by 10/31/12 on its "experience with the tariff and outlining the costs and expenses associated with the tariff and the administrative charges collected."

Vectren South

February 2011: Commission set procedural schedule.

February 2011: Comments due that respond "to the initial tariff filings"; testimony due supporting proposed tariffs; and Proposed Orders due.

February 2011: Hearing.

March 2011: "Deadline for interested customers to file with Midwest ISO concerning participating in demand response."

March 2011: Commission issued an Order that did the following:

- Approved: Vectren South's "Proposed Rider DR." This rider, the Commission explains, "provides qualifying customers the optional opportunity to reduce their electric costs by beneficially augmenting the Company's participation in the MISO wholesale energy market and the Company's efforts to preserve reliable electric service, through customer provision of a load reduction during MISO high price periods and declared emergency events. This initial Rider DR offers two programs, emergency demand response ('EDR') and demand response resource Type 1 ('DRR-l') energy programs. . . . Rider DR allows the opportunity for qualified aggregators to aggregate demand response of multiple customers and participate in Rider DR with the cumulative load."
- Directed the utility to report by 10/31/12 on its "experience with the tariff and outlining the costs and expenses associated with the tariff and the administrative charges collected."

Commission Brings Federal Court Case against FERC over PJM Program

January 2011: Commission asked the US Court of Appeals for the District of Columbia Circuit to nullify FERC's September 2009 approval (and April 2010 clarification of the approval) of a PJM demand response program that presumes the eligibility of retail customers to participate in it. In its initial brief to the court, the Commission explained that the FERC-approved program allows participation of retail customers even though in February 2009 the Commission said that Indiana retail customers could only participate in demand response programs if they had the Commission's permission. (In July 2010, the Commission decided that end-use customers may not participate in RTO demand response programs directly or through third-party service providers/aggregators—only through the load-serving entity that serves them.) Furthermore, the PJM program makes distribution companies responsible "for proving [within ten days] that participation by the customer in question is prohibited by the retail regulatory authority." The Indiana Commission continued to explain that FERC shares its position that "FERC may authorize wholesale demand response programs" but that the Commission "retains the right, as the relevant electric retail regulatory authority, to determine Indiana retail customer eligibility for those programs." The nut of the issue, then, "is whether PJM's tariff revisions approved by the FERC . . . impermissibly interfere with the Indiana Commission's retail jurisdictional authority."

LEGISLATIVE:

Clean Energy Standard

April 2011: Indiana House and Senate passed a bill that would set a clean energy portfolio standard (CPS). Qualifying clean energy resources would include energy storage as well as DSM initiatives that, after January 2010, "implement load management, demand response, or energy efficiency measures designed to shift customers' electric loads from periods of higher demand to periods of lower demand."

May 2011: Governor Daniels signed the bill. The new CPS would unfold in three timeframes:

(1) CPS Goal Period I: "For the six (6) calendar years beginning January 1, 2013, and ending December 31, 2018, an average of at least four percent (4%) of the total electricity obtained by the participating electricity supplier to meet the energy requirements of its Indiana retail electric customers during the base year."

(2) <u>CPS Goal Period II</u>: "For the six (6) calendar years beginning January 1, 2019, and ending December 31, 2024, an average of at least seven percent (7%) of the total electricity obtained by the participating electricity supplier to meet the energy requirements of its Indiana retail electric customers during the base year."

(3) <u>CPS Goal Period III</u>: "In the calendar year ending December 31, 2025, at least ten percent (10%) of the total electricity obtained by the participating electricity supplier to meet the energy requirements of its Indiana retail electric customers during the base year."

Iowa

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

Kansas

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

Kentucky

REGULATORY:

<u>EISA 2007</u>

November 2008: Commission initiative proceeding.

February 2010: Commission issued a document, "Commission Staff Smart Meter and Smart Grid Guidance,'' enumerating 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."

April 2010: Parties to the proceeding filed an "Overview and Schedule for Developing Responses to the Staff's Guidance Document."

January 2011: Commission Staff held informal conference "to review the progress of the collaborative group and discuss the final report to be issued by the collaborative group."

March 2011: Parties filed final report in response to "Commission Staff Smart Meter and Smart Grid Guidance." The report makes the following recommendations:

1. "The Commission was to determine whether or not to implement four new PURPA standards and one non-PURPA standard applicable to electric utilities and two new PURPA standards applicable to gas utilities. The parties of record recommend that the Commission should not adopt any of these standards, or any variation thereof."

2. "Pilots and trials built to understand customer behavior ***(i. e.,*** acceptance, use, sustainability of savings, etc.) and investigate emerging technology integration into existing infrastructure should be continued."

3. "Customer education about the benefits of energy efficiency and specifically smart technology is critical to gaining consumer acceptance and employment of this technology. Consequently, continued and new efforts focused on customer education should be embraced by the Commission."

4. “Resist the urge to implement prescriptive requirements for smart technology deployment.”

5. “The case participants recommend that this report conclude Case No. 2008-00408.”

The report also says that smart grid investments should be treated the same as other utility investments:

> “Specifically, all costs and benefits must be included, quantified, and allocated appropriately amongst the utility, the ratepayer, and all other contributors or beneficiaries. Uncertainties in cost and/or benefits should be addressed by appropriate risk analysis. Projects should be prioritized by net present value (NPV), investment-return ratio, or other standard financial evaluation methods which take into consideration the timing of capital costs and associated benefits.”

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:

Smart Grid Coordinator

September 2010: In compliance with Maine's Smart Grid Policy Act 2010, the Commission launched an investigation "to determine whether it is in the public interest to have one or more smart grid coordinators in the State." If the Commission decides that the role of smart grid coordinator is indeed in the interest of the state, then it will address the formation of standards related to the position. Such standards may include: "Eligibility, qualification and selection criteria"; "Duties and functions"; "The relationship between a smart grid coordinator and a transmission and distribution (T&D) utility"; "Access to information held by the smart grid coordinator by 2nd and 3rd parties"; and "Data collection and report."

September 2010: Initial case conference.

October 2010: Commission Staff circulated draft list of issues and solicited comments. Commission issued final list after comments filed.

December 2010: Parties to proceeding filed direct cases.

January 2011: Data requests on direct cases filed.

February 2011: Data requests on direct cases filed.

February 2011: Technical Conference.

May 2011: Via a Procedural Order, the Commission incorporated into the record of this proceeding Volume 1 of the Petitioner's filing in Docket 2011-138 (Request for Approval of Non-Transmission Alternative (NTA) Pilot Projects for the Mid-Coast and Portland Areas).

June 2011: Technical Conference.

Smart Metering Opt-Out

January 2011: Via a NOPR, the Commission launched an investigation of Central Maine Power's (CMP) smart meter initiative following a series of complaints filed about it. The investigation was to "determine if the alleged position of CMP (of providing no opt-out option in the Smart Meter program installation) is 'unreasonable, insufficient or unjustly discriminatory' in the context of the existing Commission Order" approving the project. CMP's smart meter deployment was initially approved by the Commission in February 2010.

January 2011: CMP filed three scenarios for how to address RF concerns: (1) Keep mechanical meters; (2) Hard wire the smart meters; and (3) Relocate the smart meters. CMP also said that providing an opt-out option for customers would undermine the business case of its smart metering program and that allowing opt-outs could jeopardize its $96 million DOE Smart Grid Grant as well as cause it to fall short of state policy goals.

January 2011: Technical Conference to consider information filed by CMP and to determine a procedural schedule.

January 2011: Commission issued Order setting procedural steps.

February 2011: Oral Data Request Responses due.

February 2011: Commission consolidated two proceedings it already had been conducting concurrently with two proceedings it opened in December 2010 in response to two separate sets of complaints about CMP's smart metering program. The first of the newly absorbed proceedings was initiated following a petition asking the Commission to "investigate the potential health effects of radio frequency (RF) radiation that is emitted from wireless smart meters" and to "explore alternative modes of data transmission, including, specifically, hard-wired as opposed to wireless smart meters." The second assimilated case is based on a complaint asking the Commission to consider "whether CMP has the legal right to (1) enter private property to replace existing meters, and (2) enter private property via radiofrequency waves." The complaint also requested that if the Commission determines that CMP does have such a right, then the Commission direct the utility to install "non-RF emitting smart meters instead of wireless smart meters." In its Decision enacting the consolidation, the Commission concludes:

- That concerns property rights concerns "are dismissed as being without merit"
- That it makes "no determination on the merits of health and safety concerns"
- That the "consolidated investigation will not include an examination of whether the technology of CMP's AMI program should be changed to an entirely non-wireless alternative."

February 2011: Technical Conference.

February 2011: Case Conference.

February 2011: Commission issued Procedural Order vacating in part a Protective Order which had shielded from public disclosure "information showing equipment pricing that if disclosed would show vendor costs for various equipment purchased by CMP as part of the AMI system" as well as "propriety vendor business and product information that is considered confidential under the vendor contract with CMP and that if released could provide confidential information to competitors." The Procedural Order action removed protection from the former of the two areas.

March 2011: Settlement conference.

March 2011: Office of Public Advocate sent the Commission a complaint alleging that CMP had been intimidating customers into accepting smart meters.

March 2011: Commission directed CMP, through a Procedural Order, to respond to the March 2011 complaint from the Office of Public Advocate alleging that CMP had been intimidating customers into accepting smart meters. CMP addressed the complaint through a March 2011 letter.

March 2011: In response to a February 2011 compliant, the Commission opened a new proceeding to investigate concerns that smart metering causes health issues. The complaint requested that the Commission "require that CMP allow us to retain our existing analog meters" and that the Commission "investigate the feasibility of 'reasonable' (to be determined by unbiased independent experts) smart-meter-free areas around the homes of individuals who have been physically impacted by smart meters." It also asked that the Commission "consult with unbiased experts in the field of pathophysiology (the effects of RF on cells) and epidemiology to further explore this issue specific to smart meter emissions."

April 2011: Commission reiterated that its investigation of concerns about CMP's smart metering program will be limited to the question of whether customers should have the option to opt out from wireless smart metering. Through an Order Denying Motion for Reconsideration, the Commission said that the proceeding will not reconsider the initial approval for CMP's smart metering program or evaluate claims of smart metering health effects. The Commission issued the Order in response to a March 2011 Motion rebutting its February 2011 NOI outlining the parameters of the case.

April 2011: Commission issued Procedural Order.

April 2011: Commission Staff filed analysis of and recommendations for allowing customers to opt-out of CMP smart metering program. The Staff recommended two opt-out options: (1) Keeping an existing electro-mechanical meter or (2) Disabling a smart meter's transmitter so that it operates in "receive-only mode." Both options would require manual meter reading "on at least a bi-monthly basis" and would therefore necessitate the fees. Beyond the two opt-out provisions, the Staff recommends that customers have the choice to have CMP "relocate a smart meter to a different point" on their property. In this scenario, the smart meter would be fully operational. Customers would have to pay the cost of moving the meter, but would not have to pay any opt-out fees.

April 2011: Commission added another proceeding to this consolidated docket. The newly-added case was opened in February 2011 subsequent to a complaint filed by eleven people requesting that the Commission (1) "require CMP to allow its customers to choose to retain their existing analog meters" and (2) "investigate the feasibility of 'reasonable' (to be determined by unbiased independent experts) smart-meter-free areas around homes of individuals who have been physically impacted by smart meters." The Commission said that it will not consider the issue of health impacts raised by the complainants.

April 2011: Parties' Comments on Staff Bench Analysis due.

May 2011: Case Conference.

May 2011: Commission issued an Order directing Central Maine Power (CMP) to allow customers to opt-out of its smart metering program. CMP must offer two opt-out options: (1) using an already-installed smart meter "with its transmitter turned off" and (2) keeping an existing analog meter. Upon notification of the opt-out options, customers will have 30 days to elect one. Further, customers choosing to opt out must pay "the associated costs of that option":

- Option 1—Smart Meter with Disabled Transmitter: "Initial charge of $20.00 and a monthly charge of $10.50"

- Option 2—Existing Analog Meter: "Initial charge of $40.00 and a monthly charge of $12.00."

- Low-Income Customers: ". . . those who are eligible for Low Income Heating Assistance (LIHEAP), will be charged only 50% of the cost of their chosen opt-out option."

The Order also compeled CMP to effect a "smart meter opt-out communication plan intended to inform customers about the program during the company's deployment of their smart meter program."

May 2011: Commission closed two other proceedings. One proceeding was initiated following a complaint seeking an investigation of the potential fire hazards of smart meters. The other proceeding was an investigation of whether smart meters interfere with other electronic and medical devices.

May 2011: CMP filed revised tariff sheets incorporating "the requirements CMP's Smart Meter Opt-Out Program as described in the Order dated May 19, 2011."

June 2011: The Commission issued "Part II" of its Order directing CMP to allow customers to opt-out of its smart metering program. Part II of the Order lays out the Commission's analysis of the issues and the reasoning for its decision. Part II of the Order methodically addresses the following:

- Smart Meter Opt-Out
- Opt-Out Alternatives and Pricing
- Low-Income Assistance
- Enrollment Process
- Communication Plan
- Opt-Out Metering
- Opt-Out Cost Deferral and Reconciliation.

In summation, the Order states:

"In light of the magnitude of concerns among a significant portion of its customers, CMP's response that those concerns lack of credible scientific evidence misses the point. CMP is a public utility that provides a monopoly service. Customers that are dissatisfied with CMP service cannot obtain electricity . . . service from another provider. As such, responsiveness to customer concerns and customer acceptance of the terms and conditions of service are important considerations with respect of public utility service. Under the circumstances presented in this case, it is clearly an unreasonable act and practice for a utility to ignore the concerns of a significant number of its customers and refuse to permit a smart meter opt-out option if doing so is technically and economically feasible and those customers assume and bear the additional costs. The Staff bench analysis and information in the record in this proceeding demonstrate that a smart meter opt-out in the context of CMP's AMI program is technically and economically feasible. We, therefore, find that CMP's AMI initiative, without an opt-out alternative, is an unreasonable utility act and practice and we direct CMP to provide customers with opt-out alternatives as specified in this Order."

Maine Center for Disease Control Concludes Smart Meters Don't Post Health Threat

October 2010: Maine's Public Advocate asked the state's Director of Public Health "to look into concerns raised by residents that the 'smart' electricity meters being installed by Central Maine Power Co. are a potential health hazard." The Public Advocate took this step in response to customers' complaints, one of which suggests that "the [forthcoming] meter network is comparable to having a cell phone tower outside every home, and that people have reported heart palpitations, migraines and other problems where the [smart] meters are installed." The Public Advocate advised inquirers that he is not qualified to assess public health issues and that concerns should be expressed to the Maine Public Utilities Commission.

November 2010: Maine's Center for Disease Control (CDC) published its final review of smart metering, finding that smart meters indeed do not pose a health threat:

> "In conclusion, our review of these agency assessments and studies do not indicate any consistent or convincing evidence to support a concern for health effects related to the use of radiofrequency in the range of frequencies and power used by smart meters. They also do not indicate an association of EMF exposure and symptoms that have been described as electromagnetic sensitivity."

LEGISLATIVE:

Enabling Smart Meter Opt-Out

March 2011: Bill introduced in the Maine House of Representatives. As introduced, the bill would direct the Maine Public Utilities Commission to set the terms and conditions enabling customers to opt out, "at no cost," from receiving wireless smart meters; to have removed wireless smart meters previously installed; and to mandate the option of receiving a wired instead of a wireless smart meter. At the same time, however, the bill would set state smart grid policy and goals, and there is legislative language that focuses on the positive attributes of smart metering.

June 2011: Bill passed both House and Senate.

June 2011: Bill signed by Governor Paul LePage. The provisions of the enacted law include the following directives for the Public Utilities Commission:

- “examine current cyber security and privacy requirements that exist under federal and state law, rules and utility policies and practices that apply to transmission and distribution utilities and identify potential regulatory gaps . . . regarding smart meters and related systems. To the extent regulatory gaps exist, the commission shall develop recommendations to address them.”

- “consider issues related to access to customer data and the disclosure of transmission and distribution utility residential electric energy consumption and cost information. . . .”

- “actively monitor the efforts by the United States Department of Energy to launch a cyber security initiative to enhance cyber security on the electric grid with input from the Federal Energy Regulatory Commission, the United States Department of Homeland Security and publicly and privately owned utilities. . . .”

- “report the results of its examination and recommendations required pursuant to section 1 and the progress of the federal cybersecurity initiative as it applies to smart meters and related systems under section 2 to the Joint Standing Committee on Energy, Utilities and Technology by January 15, 2012. The Joint Standing Committee on Energy, Utilities and Technology may submit a bill to the Second Regular Session of the 125th Legislature based on the report.”

Resolution to Protect Ratepayers Relative to Smart Metering

February 2011: Bill introduced in the Maine House of Representatives. The bill would impose “a one-year moratorium on the installation of smart electric meters”; would require “an electric utility to remove a smart electric meter from a customer's premises at the request of the customer for a fee not exceeding $30”; and would direct “the Public Utilities Commission to study the safety of smart electric meters and report its findings to the Joint Standing Committee on Energy, Utilities and Technology."

April 2011: Bill introduced in Senate.

Requiring Smart Metering Safeguards

April 2011: Bill introduced in the Maine House of Representatives. The bill would do the following:

- Amend "the State's smart grid policy to include consideration of customer rights."

- Require "the Public Utilities Commission to initiate a proceeding whenever a transmission and distribution utility is going to install a wireless smart meter. The proceeding must order the transmission and distribution utility to protect customer rights when a wireless smart meter is installed, including providing opt-out provisions and wired smart meter alternatives, protection from unreasonable fees or rate increases and protection of customer data, including name, address, telephone number, electricity use and payment information."

- Require the Public Utilities Commission "to take similar action to protect a customer that had a wireless smart meter installed prior to the effective date of this provision."

June 2011: Bill declared in both House and Senate to be "dead."

Maryland

REGULATORY:

EmPOWER Maryland Act

Back Ground: In September 2008, Maryland utilities complied with the EmPOWER Maryland Energy Efficiency Act of 2008 by filing with the 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 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. 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."

September 2010: Commission began the process of establishing the EmPOWER Maryland consumption- and demand-reduction plans for 2012 – 2014 when it issued its "Consensus Report on the Development of 2012 – 2014 Utility EmPOWER Maryland Plans." The report outlines the course of action to be taken, which was set by the Commission's Staff, the Maryland Energy Administration (MEA), and the Office of the People's Counsel. According to the EmPOWER Maryland Act, utilities filing a 2012 – 2014 plan are to consult with the MEA by July 2011 "regarding the design and adequacy" of their plan. By September 2011, the utilities are to file their plan with the Commission. The plans must describe proposed demand response, efficiency and conservation programs; identify projected costs; and forecast electricity and demand savings. The September 2010 consensus report outlines the course of action to be taken on the 2012 – 2014 plans as determined by the Commission's Staff, the Maryland Energy Administration (MEA), and the Office of the People's Counsel:

- EmPower 2012 – 2014 Work Group: The EmPOWER 2012 – 2014 Work Group is the medium for "informal meetings" about the "development and review" of EmPOWER Maryland Plans. Any interested stakeholder may participate in such meetings. The Work Group is facilitated by Commission Staff.

- Stakeholder Proposals for the Plans—Fall 2010: The Commission is seeking proposals from stakeholders other than the five utilities beholden to the EmPOWER Maryland Act. Proposals may be for demand response, efficiency, and conservation programs that aim to meet the law's goals. This is not formal request process.

- Utilities Develop Draft Plans—Winter 2011: Utilities are basing their 2012 – 2014 plans on their 2009 – 2011 programs; on "the results of the EmPOWER Maryland Baseline Study and EM&V Process; on "the work products of the EM&V Forum"; on "evolving energy efficiency, conservation and demand reduction best practices nationwide"; and on "selected stakeholder input and proposals into a Draft Plan."

- EmPower 2012 – 2014 Work Group Review of Draft Plans—Spring 2011: "The Work Group will study and provide feedback to MEA and the Utilities on the merits of the Draft Plans regarding the achievement of the utilities' 2013 peak demand reduction and 2015 electricity savings and peak demand reduction targets."

- Final Adjustments and Refinements to Draft Plans—Summer 2011: "Utilities and/or their program development contractors will finalize their Plans for filing with the Commission on or before September 1, 2011."

- Post-filing Work Group Informational Meetings As Needed—September 2011: "Staff and the interested parties will discuss the merits of having the Work Group serve as an informal discovery process to assist party and stakeholder understanding of the filed Plans prior to parties' filings and Commission hearings on the Plans. Staff welcomes any guidance from the Commission as well."

- Plan Hearings—Fall 2011: "The Utilities, MEA, Staff and OPC anticipate proceedings on individual utility Plans similar to the process for the 2009 – 2011 Plans with hearings scheduled during the fall of 2011."

September 2010: Commission invited stakeholders, other than the five utilities subject to the EmPOWER Maryland Act, to propose "new or revised programs, measures or products." Proposals were due in October 2010.

October 2010: Hearing on "the impact of various demand response proposals being considered by PJM Interconnection, LLC on BGE's and the PHI Companies' Advanced Metering Infrastructure business cases and on BGE's, the PHI Companies' and SMECO's approved demand response programs contained in their EmPower Maryland Programs."

November – December 2010: The EmPOWER 2012 - 2014 Work Group held meetings.

December 2010: Hearing to review EmPOWER Maryland Reports for the second and third quarters of 2010 filed by utilities. Comments filed on reports prior to Hearing.

March 2011: Hearing to discuss a February 2011 joint letter from the Commission Staff and the Office of People's Council expressing "concern about certain initiatives" that Pepco and Delmarva Power & Light (DP&L) implemented under their direct load control programs. The letter indicated that the "Staff and OPC were unaware" of these initiatives until the Pepco Holding Inc. companies filed their 2010 annual report on their EmPOWER Maryland Programs.

March 2011: Hearing to consider the 2010 EmPower Maryland Annual Reports filed by utilities. Comments on the reports filed prior to the Hearing.

March 2011: The utilities filed their draft 2012 – 2014 EmPOWER Maryland consumption- and demand-reduction plans.

March 2011: Commission Staff published its "Annual 2010 EmPower Maryland Overall Implementation & EM&V Progress Report." In it, the Staff concluded that the utilities are not on pace to meet the 2011 EmPower Maryland goals. The report says:

- The collective results, "as of the fourth quarter of 2010," of the utilities' EmPOWER Maryland programs are:
    - "Installed about 5,476,571 energy savings measures for 765,625 participants, producing 387,452 MWh of reported annualized energy savings and 270.216 MW of peak demand reduction."
    - "Demand Response Programs contributed 216,048 installed measures and 234.64 MW, 86 percent, of peak demand reduction."
- "To date, the programs have achieved [since they were implemented] about 644.083 MW in reported peak demand reduction and 551,858 MWh in reported annualized energy savings; which is 32 percent and 26 percent, respectively, of the Utilities' 2011 targets. *These demand reduction and energy savings represent 39 percent and 11 percent of the 2011 EmPower Maryland goals, respectively.*"

The paper also provides a detailed comparison of the reported energy and demand savings relative to those forecasted for 2011 by the utilities as well as relative to the 2011 EmPOWER Maryland goals.

April – May 2011: Commission Staff held a series of informal meetings to enable stakeholders to provide feedback on the 2012 – 2014 EmPOWER Maryland consumption- and demand-reduction plans to be filed by utilities. These meetings were not formal hearings before the Commission. The Maryland Energy Administration, however, participated in them along with the Commission Staff.

April 2011: Commission Staff filed with the Commission the Cost Allocation Consensus Document for the EmPower Maryland Plans In response, the Commission announced that it would consider the document at an April 2011 Administrative Meeting.

April 2011: Pepco proposed a pilot for "master-metered buildings to explore the practicability of expanding" its Energy Wise Rewards Program. The pilot would consist of smart thermostats and outdoor cycling switches and loggers at 40 master-metered residencies.

May 2011: Commission granted Allegheny Power's May 2011 request to delay filing of "First Quarter 2011 EmPOWER Maryland Report" until later in the month.

May 2011: BGE and SMECO each filed its "First Quarter 2011 EmPOWER Maryland Report."

May 2011: Delmarva Power & Light and Pepco filed a load-impact evaluation of their Energy Wise Rewards direct-load-control program. As the utilities explained in their report, "The study was performed to comply with PJM demand response market rules and to validate load impacts from the new smart thermostats and outdoor cycling equipment." The report looks at the program's effectiveness during the summer of 2010.

May 2011: Commission Staff filed its "Verification of Reported Energy and Peak Savings from the EmPOWER Maryland Energy Efficiency Programs." The report concludes that the "verified kWh saving estimate are 3% higher than evaluated kWh savings and verified kW savings are 3.5% higher than evaluated savings." It also says that the "analysis verified 95% of the energy and 85% of the peak savings reported by the Empower Maryland utilities."

May 2011: Allegheny Power, Pepco, and Delmarva Power & Light each filed their "EmPower Maryland First Quarter 2011 Report."

May 2011: The Office of People’s Counsel filed comments opposing Pepco’s proposed pilot for “master-metered buildings to explore the practicability of expanding” its Energy Wise Rewards Program.

June 2011: Commission asked the Maryland Energy Administration (MEA) to appear at a June 2011 Administrative Meeting to provide an update on whether it would be able to fund, after June 2011, the Northeastern Energy Efficiency Partnership's (NEEP) Evaluation Monitoring and Verification Forum. The MEA has been funding the participation of Maryland’s IOUs in the NEEP EM&V Forum since it notified the Commission in November 2009 that it received approval in August 2009 from the Maryland Board of Public Works to enter into a “sole source contract” with NEEP. The Commission’s interest in sustaining utility participation in the NEEP EM&V Forum is for the sake of encouraging the application of EM&V practices to the utilities’ EmPOWER Maryland programs.

June 2011: Joint Motion filed by the Maryland Energy Administration, Commission Staff, Office of People’s Counsel, Allegheny Power, BGE, Pepco, Delmarva Power, and SMECO. The Joint Motion recommended that $198,157 in funding to complete the 2011 NEEP EM&V Forum projects “come from the EmPOWER budgets of the five Maryland EmPOWER utilities with associated cost recovery. . . .” The Joint Motion also said that “all parties concur that the projects completed through the NEEP EM&V Forum has provided valuable products useful to the State of Maryland and that continuation of funding should occur for the balance of the 2011 projects.”

June 2011: Commission approved request in Joint Motion for the allocation of $198,157 in funding to complete the 2011 NEEP EM&V Forum projects.

Demand Response and Federal End-Use Customers

July 2010: The Commission initiated a proceeding to collect information about “federal end-user customers’ participation” in demand response programs run by curtailment service providers registered with PJM. It issued a Notice directing all electric utilities—including municipal and cooperative utilities—to file comments providing “information about estimated load associated with federal end-users, the extent to which federal end-users already participate in DR programs, and estimated or known load reductions associated with federal end-users’ current or potential participation in DR programs.” Baltimore Gas & Electric in particular, however, is to address an additional set of comments about its facilitation of federal end-users’ participation in demand response through its "optional billing service whereby end-user customers may elect to receive DR compensation from third-party CSPs in the form of BGE bill credits."

April 2011: Legislative-style hearing "to consider the comments filed in the proceeding and to determine what further actions, if any, should be directed by the Commission."

Performance of PJM's Reliability Pricing Model

August 2010: Commission solicited comments on nine questions, including:

1. "What changes have been considered to RPM or within the PJM stakeholder process that could potentially facilitate more levelized capacity prices throughout the RTO?"

2. "What changes could be made to RPM that would stimulate increased generation and demand response investment in Maryland? Should RPM be kept as is, amended or abandoned?"

3. "Should the Commission monitor or regulate the participation of regulated electric companies with regard to their capacity offers of Demand Response and Energy Efficiency? If so, how? If not, why not?"

4. "What mechanism exists in PJM's market rules and procedures that allows PJM to inform and share data with state commissions of the specific measures that could be undertaken by the state commissions to reduce energy and capacity costs for customers, and how do such procedures operate?"

5. "Why was the capacity clearing price for the 2013-14 planning year so much higher in MAAC than the clearing price for the 2012-13 planning year? What changed? What new price signals or economic incentives does the higher 2013-14 clearing price send?"

October 2010: Comments due.

October 2010: Commission held a Public Conference to hear feedback on issues related to PJM's Reliability Pricing Model (RPM) and the results of the 2010 Base Residual Auction for the 2013 – 2014 delivery year. The Commission held the meeting because it determined that it was "time to gain a better understanding of the market forces driving RPM results." The Commission said that the "RPM has not only failed to attract new generation," but that it "has also not attracted a sustained increase in demand response participation."

<u>Whether Curtailment Service Providers are Electricity Suppliers</u>

<u>August 2010</u>: Commission Order opening a proceeding to consider the question of whether Curtailment Service Providers (CSPs) operating in the state should be "regarded as electricity suppliers" and, therefore, be required to obtain the necessary license from the Commission. The proceeding is to also consider the question of "whether to require periodic reports from the CSPs in the event that the Commission determines that the CSPs are subject to licensing by the Commission." The initiating Order summarizes Commission Staff's argument that CSPs should be treated as electricity suppliers:

- Commission Articles do not define a "CSP"

- "Staff submits that the demand response services provided by CSPs 'are often seen as part of a supply portfolio and as a substitute for increased generation or transmission.'"

- "Additionally, Staff cites language from the § 7-211(b)(2) of the PUC Article that 'states that the purpose of the conservation, energy efficiency, and demand response targets in the legislation is "to provide affordable, reliable, and clean energy for consumers of Maryland."'"

- "Finally, Staff states that 'PJM pays CSPs for their demand response effort as a means of ensuring a reliable flow and supply of electricity across the electric grid it controls.'"

- "Staff makes the additional argument that, unless CSPs are licensed or regulated by the Commission, the Commission will be unable to fulfill its responsibilities under § 2-113 of the PUC Article5 and § 7-201 of the PUC Article."

- "Staff asserts that, unless the Commission has knowledge of the demand response activity of the CSPs in Maryland" then the Commission may not take action "such as ordering excessive utility investment in demand response and conservation programs, which may not be cost-effective or needed."

<u>September 2010</u>: Deadline for intervention.

September 2010: Comments due.

October 2010: Reply comments due.

January 2011: Notice of Hearing scheduling a legislative-style hearing.

February 2011: Legislative-style hearing.

Maryland Commission Electric Vehicle Technical Conference

October 2010: Commission hosted an Electric Vehicle Technical Conference. The event featured presentations from car makers, policymakers, academics, and the electricity industry. Topics focused on the "technology and practical implications" of electric vehicles. The agenda included discussion on "Grid Impacts & Implications"; "Electric Vehicle as a Distributed Generator"; and "Consumer & Regulatory Impacts & Implications."

LEGISLATIVE:

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

Massachusetts

REGULATORY:

Smart Grid Pilot Evaluation Working Group Green Communities Act 2008

July 2010: The Department of Public Utilities created the Smart Grid Pilot Evaluation Working Group "to provide a forum in which the Department, the electric distribution companies and other interested persons can work together to develop, to the extent reasonable, uniform statewide smart grid evaluation approaches and standards." The pilots in question are those utilities created in compliance with the state's Green Communities Act 2008.

March 2011: The Smart Grid Pilot Evaluation Working Group filed with the Department of Public Utilities the “evaluation framework” it created for the smart grid pilots. The evaluation framework was in the form of three consensus documents: (1) the Common Evaluation Framework; (2) Appendix A of the Common Evaluation Framework; and (3) Pre-Pilot Survey Questions. The Common Evaluation Framework, as the Working Group described it, “is intended to establish a uniform approach to the collection of data relating to the Smart Grid Pilots, but specifically does not attempt to establish a methodology to calculate costs and benefits associated with a full scale deployment of any technology or alternative pricing program.” The Pre-Pilot Survey Questions, meanwhile, “will gather information from Pilot participants before the Pilot begins and will provide a ‘...minimum set of consistent data will facilitate post-Pilot cross-utility comparisons.’”

May 2011: The Technical Subcommittee of the Smart Grid Pilot Evaluation Working Group filed two more survey documents with the Department of Public Utilities: (1) the “Smart Grid Collaborative Post-Installation Survey” and (2) the “Smart Grid Collaborative Non-Participating Customer Survey.”

LEGISLATIVE:

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

Michigan

REGULATORY:

Michigan Smart Grid Collaborative

June 2010: The Smart Grid Collaborative met for the first time since March 2008. Topics discussed include “coordination of utilities infrastructure deployment in service territory overlap areas” and coordination of pilot programs. The Smart Grid Collaborative was created by the Commission in April 2007.

October 2010: The Smart Grid Collaborative met to discuss the creation of a new structure for the group. The meeting was predicated on the following statement:

> "The Commission is reorganizing the Michigan Smart Grid Collaborative so as to increase stakeholder ownership, to promote partnerships between utilities, regulators and key public stakeholders, to enhance research, development and demonstration of smart grid technology, to reduce the costs to be borne by utility ratepayers, and to facilitate Michigan's presence in the development of national standards. In order for industry leaders to have a more effective presence in determining Michigan's energy future, four technical workgroups have been created along with a steering committee."

January 2011: Smart Grid Collaborative meeting.

May 2011: Commission held a Smart Grid Symposium. The event featured the following panel sessions:

- National Policy Developments on Smart Grid
- National Standards for Smart Grid
- Effective Regulatory Policies for Smart Grid
- Vehicle to Grid Revolution
- Exploring the Potential of Smart Meters
- Making the Business Case for Smart Grid—A Utility Perspective
- Personal Privacy and Smart Grid
- Making the Nexus between Smart Grid and Security
- Making the Most of Smart Grid—Customer Education Programs
- Cyber Security for Energy Delivery Systems
- Smart Grid Interoperability Standards (NIST)
- Smart Grid Technologies
- Data Collection and Consumer Privacy.

LEGISLATIVE:

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

Minnesota

REGULATORY:

Direct Bidding of DR into MISO by ARCs

January 2010: The Commission opened the proceeding and solicited comments about "the potential effects of ARCs on utility rates, reliability, demand-side management, conservation programs; on participating and non-participating utilities and customers; and other relevant issues, to help inform the Commission on whether it should take action with respect to the possible operation of ARCs in Minnesota." This proceeding is the Commission's response to FERC's October 2009 Order 719 in Docket RM07-19 and AD07-7 (Wholesale Competition in Regions with Organized Electric Markets), which directs RTOs "to amend their market rules to allow Aggregators of Retail Customers (ARCs) to bid demand response resources from retail customers of larger utilities directly into the RTO's organized wholesale energy and ancillary services markets, unless the laws or regulations of the retail regulatory authority do not permit retail customers to participate." In October 2009, MISO filed with FERC revisions to its Open Access Transmission, Energy and Operating Reserve markets Tariff.

February 2010: Comments filed.

March 2010: Reply comments filed.

April 2010: The proceeding was addressed at a Commission meeting.

May 2010: The proceeding was addressed at a Commission meeting.

May 2010: The Commission issued an Order prohibiting "the demand response of the retail customers of Xcel Energy, Minnesota Power, Interstate Light and Power, and Otter Tail Power from being bid into organized markets by non-utility aggregators of retail customers." It also directed these utilities to "make filings describing their demand response programs, analyzing the effectiveness of these programs, and discussing how effectiveness could be improved, as by conducting pilot projects, issuing requests for proposals, or other mechanisms." Furthermore, the Commission directed the utilities to file, by September 2011, two reports:

- “a report on ARC operations in the wholesale markets operated by MISO and in the wholesale markets operated by other independent system operators and regional transmission organizations, focusing specifically on the impact of ARC operations on prices, reliability, nonparticipating customers, utility operations, and utility-operated demand response programs”

- “a report on the tariff and program changes that each utility believes would be necessary to accommodate ARC operations in Minnesota.”

August 2010: Reply comments filed.

July 2010: Comments filed on utilities’ June 2010 filings.

June 2010: Utilities filed DR descriptions in compliance with May 2010 Order.

January 2011: At its regularly scheduled meeting, the Commission considered what further action it should take in this proceeding.

February 2011: Commission issued an Order affirming the potential benefit of allowing utilities to consider expansion of “demand response options in Minnesota through contracts with third-parties.” Furthermore, the Order directs Xcel Energy, Minnesota Power, Interstate Power and Light, and Otter Tail Power to file comments about “the ability to expand demand response options through contracts with third parties in order to achieve demand response potential.” Interstate Power and Light also is to file comments about “demand response potential in its service territory in Minnesota and specific efforts it will take to improve its demand response.” These comments are due in September 2011.

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

REGULATORY:

ARCs and Direct Participation of Retail Customers in Wholesale DR Markets

January 2010: The Missouri Public Service Commission initiated this proceeding to investigate "how to achieve its new responsibilities" relative to the Missouri Energy Efficiency Investment Act (Senate Bill 376) as well as to determine how to move forward relative to FERC Order 719 (Dockets AD07-7 and RM07-19, "Wholesale Competition in Regions with Organized Electric Markets"). The Missouri law "declares that the policy of Missouri is to value demand-side investments equal to traditional investments in supply and delivery infrastructure." It requires, among other things, "the Commission to direct the implementation of demand-side programs 'with a goal of achieving all cost effective demand-side savings,' coupled with timely cost recovery and alignment of utility financial incentives with energy efficiency."

March 2010: Commission issued an Order prohibiting, until further notice, "demand response load reductions of customers of the four Missouri electric utilities regulated by the Commission . . . from being transferred to ISO or RTO markets directly by retail customers or third party ARCs."

January 2011: Commission issued a Draft Rule with the following provisions:

- "An Aggregator of Retail Customers (ARC) shall not directly aggregate the Demand Response of a commercial customer or industrial customer of an electric utility where the Commission is the Relevant Electric Retail Regulatory Authority (RERRA) unless:
    - o The ARC is properly registered as a market participant with the Independent System Operator / Regional Transmission Organization (ISO / RTO) that the Electric Utility is a member of, as defined in relevant ISO / RTO tariff or Business Practice Manual; and

- The Demand Response of that retail customer, added to the existing Demand Response already aggregated by ARCs in the electric utility's Balancing Authority Area, is less than 100 megawatts (MW); and

- The ARC has followed the proper ISO / RTO procedure, as described in the ISO / RTO's Open Access Transmission Tariff (OATT) and / or Business Practice Manual, regarding registering the Retail Customer's Demand Response; and

- The customer is not currently enrolled in the same type of Demand Response program, Economic or Ancillary Services, with an Electric Utility or Load Serving Entity (LSE)."

- "An Electric Utility or LSE shall not enroll a Retail Customer into an Economic or Ancillary Services Demand Response program if that Retail Customer is currently enrolled in the same type of Demand Response program with an ARC."

- "An ARC may not directly aggregate the Demand Response of a Residential Customer of an electric utility where the Commission is the RERRA, unless the Commission makes an affirmative decision that ARCs aggregating the Demand Response of Residential Customers is not detrimental to the public interest."

- "The Commission Staff shall provide a recommendation no later than 3 years of the effective date of the rule whether ARCs directly aggregating the Demand Response of Residential Customers is not detrimental to the public interest."

- "An ARC may enter into a contract agreement with an Electric Utility or LSE to aggregate Commercial, Industrial or Residential Customers in behalf of the Electric Utility or LSE."

- "The Commission reserves the right to set the Marginal Foregone Retail Rate (MFRR), or any successor or equivalent to the MFRR."

<u>January 2011</u>: Commission workshop to consider a draft rule. At the workshop, the Commission Staff solicited comments generally addressing the draft rule as well as comments specifically proposing changes to the draft rule.

<u>February 2011</u>: Comments due.

April 2011: MISO filed comments explaining that it "is currently considering the implications of this recent FERC DR Compensation Rule with specific emphasis on the possible impacts to the still pending MISO filing on Aggregators of Retail Choice (ARC) to comply with FERC Orders 719 and 719-A." (The FERC Rule was issued in March 2011; it requires ISOs and RTOs to pay full locational marginal price (LMP) for demand response resources "when those resources have the capability to balance supply and demand as an alternative to a generation resource and when dispatch of those resources is cost-effective.")

April 2011: Commission held an ARC/ISO/RTO Demand Response and Aggregation Draft Rule Workshop. The meeting's goals were to (1) Obtain input from stakeholders regarding draft rule and (2) Address and discuss the issues, questions and concerns from stakeholders.

April 2011: Commission Staff solicited, via email, comments on portions of the draft rule not discussed during an April 2011 meeting due to time constraints. This solicitation did not constitute the beginning of a formal comment period. The Staff said at the April 2011 meeting that once it collects these informal comments it will present its findings to the Commission. Only then might a formal process for the draft rule, with a formal comment process, commence.

April 2011: Comments due

Consideration and Implementation of Missouri Energy Efficiency Investment Act

June 2010: Commission Staff filed proposed rules "to implement the provisions of Section 393.1075, the Missouri Energy Efficiency Investment Act."

July 2010: Staff filed revised proposed rules.

August 2010: Order directing (1) Staff to file "the most up-to-date draft of the rules no later than August 26, 2010"; (2) "any participant to the rulemaking process that has any legal issue or concern in relation to the rules…[to] file a comprehensive list of issues with the Commission no later than September 7, 2010"; and (3) "any participant identifying an issue pursuant to ordered paragraph number…[to] provide the commission with a full legal briefing of that issue no later than September 14, 2010."

August 2010: Staff filed revised proposed rules.

September 2010: Filings made reflecting the "list of issues" of parties to the proceeding.

September 2010: Legal briefings filed.

October 2010: Commission issued Proposed Rule.

December 2010: Comments on Proposed Rule filed.

December 2010: Hearing.

February 2011: Commission issued an Order adopting four Rules:

- 240-20.093 Demand-Side Programs Investment Mechanisms
- 240-3.164 Electric Utility Demand-Side Programs Filing and Submission Requirements
- 240-3.163 Electric Utility Demand-Side Programs Investment Mechanisms Filing and Submission Requirements
- 240-20.094 Demand-Side Programs

March 2011: Multiple parties filed Applications for Rehearing.

March 2011: Commission issued an Order denying Applications for Rehearing.

June 2011: Commission issued an Order closing proceeding.

LEGISLATIVE:

Missouri Energy Efficiency Investment Act

- February 2009: Bill introduced in Missouri Senate that would promote demand response and load management.
- April 2009: Bill passed in Senate and introduced in Missouri House.
- May 2009: Bill passed in House.
- July 2009: Bill signed by Governor Jay Nixon. Provisions include:

“3. It shall be the policy of the state to value demand-side investments equal to traditional investments in supply and delivery infrastructure and allow recovery of all reasonable and prudent costs of delivering cost-effective demand-side programs....”

“4. The commission shall permit electric corporations to implement commission-approved demand-side programs [including demand response and load management] proposed pursuant to this section with a goal of achieving all cost-effective demand-side savings. Recovery for such programs shall not be permitted unless the programs are approved by the commission, result in energy or demand savings and are beneficial to all customers in the customer class in which the programs are proposed, regardless of whether the programs are utilized by all customers. The commission shall consider the total resource cost test a preferred cost-effectiveness test. Programs targeted to low-income customers or general education campaigns do not need to meet a cost-effectiveness test, so long as the commission determines that the program or campaign is in the public interest....”

“5. To comply with this section the commission may develop cost recovery mechanisms to further encourage investments in demand-side programs including, in combination and without limitation: capitalization of investments in and expenditures for demand-side programs, rate design modifications, accelerated depreciation on demand-side investments, and allowing the utility to retain a portion of the net benefits of a demand-side program for its shareholders....”

“10. Customers electing not to participate in an electric corporation's demand-side programs under this section shall still be allowed to participate in interruptible or curtailable rate schedules or tariffs offered by the electric corporation.”

“11. The commission shall provide oversight and may adopt rules and procedures and approve corporation-specific settlements and tariff provisions, independent evaluation of demand-side programs, as necessary, to ensure that electric corporations can achieve the goals of this section....”

“12. Each electric corporation shall submit an annual report to the commission describing the demand-side programs implemented by the utility in the previous year. The report shall document program expenditures, including incentive payments, peak demand and energy savings impacts and the techniques used to estimate those impacts, avoided costs and the techniques used to estimate those costs, the estimated cost-effectiveness of the demand-side programs, and the net economic benefits of the demand-side programs."

Montana

REGULATORY:

<u>**Bill to Ban Inverted Block Rate Structures**</u>

<u>December 2010</u>: Bill introduced in the Montana Senate that would limit the Montana Public Service Commission's "ability to implement inverted block rate structures for electric service." The legislation would prohibit the Commission from prescribing inverted block rate structures unless "it determines that a utility's actual costs justify an inverted block rate." The bill's preamble argues, "If used improperly, inverted block rate structures CAN create substantial discrimination between electric customers in similar rate classes."

<u>January 2011</u>: Bill passed the Senate Energy and Telecommunications Committee.

<u>February 2011</u>: Bill referred to the House Federal Relations, Energy, and Telecommunication Committee.

<u>April 2011</u>: Bill "died" in House Federal Relations, Energy, and Telecommunication Committee.

LEGISLATIVE:

No legislative 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

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

New Hampshire

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

New Jersey

REGULATORY:

2011 Energy Master Plan

Background: In October 2009, Governor Corzine released the 2008 New Jersey Energy Master Plan (EMP), the first such plan in the state in 15 years.

August 2010: BPU announced that it would evaluate the 2008 EMP relative to contemporaneous electricity needs and usage.

August 2010: Stakeholder Conference on Data Analysis and Assumptions.

<u>September 2010</u>: Stakeholder Panel Discussion on Energy, Environment, and Economic Development.

<u>September 2010</u>: Stakeholder Open Forum on Proposed Changes and Future Outlook.

<u>September 2010</u>: Comments due.

<u>June 2011</u>: Governor Chris Christie issued the state's draft "2011 Energy Master Plan." At the same time, the BPU scheduled three public hearings on the draft 2011 EMP. It also solicited comments. As it stands, the draft sets the course for meeting five overarching goals that are to "drive down the cost of energy for all customers while promoting clean, environmentally safe renewable sources of energy." One of these five goals is specifically to reduce peak demand. All but one of the goals—reducing the costs of energy for consumers—are coupled with detailed recommendations in the plan. The "plan for action" for the other four goals is:

1. <u>Promoting a Diverse Portfolio of New, Clean, In-State Generation</u>:

    a. Constructing new generation and improving Pennsylvania-New Jersey-Maryland Interconnection, LLC. (PJM) rules and processes;
    b. Assessing the implications of lost nuclear capacity;
    c. Expanding Distributed Generation (DG) and Combined Heat and Power (CHP);
    d. Supporting behind-the-meter renewables;
    e. Promoting effective use of biomass and waste-to-energy; and
    f. Promoting the safe expansion of the interstate natural gas pipeline system.

2. <u>Renewable Energy Portfolio Standard of 22.5% by 2021</u>

    a. Building upon the Christie Administration's commitment to solar energy for both economic and environmental benefits;
    b. Expanding implementation of commercial and industrial solar projects;
    c. Promoting the development of large solar generation projects on brownfield sites and landfills to offset the costs to cap or remediate these sites;
    d. Promoting development of solar to assist local governments reduce energy costs; and
    e. Maintaining support for offshore wind by codifying the statutory requirements of the Offshore Wind Economic Development Act

(OWEDA). This provides a framework for setting offshore wind renewable energy certificate (OREC) prices and for approving applications to facilitate the financing of offshore wind projects; and

f. Saying no to new coal-fired generation in New Jersey.

3. <u>Energy Efficiency, Energy Conservation and Cost-Effective Renewable Resources</u>

   a. Reducing peak demand and lowering capacity costs;
   b. Promoting energy efficiency and demand reduction in State buildings;
      i. New Jersey will lead by example and continue to improve the EE of State owned and operated buildings. In addition to existing programs, the State will take advantage of recent legislation that allows State agencies to contract with third parties with "know-how" and financial resources to implement and fund EE measures in government owned and/or operated buildings without upfront capital investment. Operating costs will be lowered by using performance-based contracting for capital improvements to energy equipment such as lighting upgrades, heating, ventilation and air conditioning (HVAC) replacement, and the installation of building automation systems.
   c. Incorporating aggressive energy efficiency in building codes;
   d. Redesigning the delivery of State energy efficiency programs;
   e. Monitoring PJM's Demand Response Initiatives;
      i. PJM is in the process of implementing many incentives and resources to support demand response (DR) to make it easier for those resources to participate and be rewarded through PJM's energy and capacity markets. New Jersey should monitor actively how new incentives inspired by FERC's recent rulemaking affect incremental DR in order to maximize the State's participation in these programs.
   f. Improving natural gas energy efficiency; and
   g. Expanding energy conservation education and outreach to assist consumers in reducing usage.

4. <u>Emerging Technologies for Transportation and Power Production</u>

   a. Improving transportation efficiency;
   b. Reducing carbon emissions and pollutants;

c. Using fuel cell technology;
d. Using energy storage technologies;
   i. Energy storage has a promising future, especially when coupled with intermittent resources like solar and wind. The new technologies include compressed air energy storage, flywheels, advanced battery systems and plug-in hybrid electric vehicles. New Jersey should continue to monitor the evolving development and improvement of energy storage technologies.
e. Assessing smart grid demonstrations; and
   i. New Jersey expects that smart grid technology will be an integral part of the energy balance throughout the State. An ongoing demonstration project will allow parties to evaluate its cost effectiveness before we make any policy decisions.
f. Considering Dynamic Pricing and Smart Metering
   i. New Jersey will expand implementation of smart meters and gradually expose customers with lower energy demands who wish to take advantage of dynamic pricing to encourage wiser energy use and reduce retail prices for all residents

<u>July 2011</u>: Public hearing in Newark.

<u>August 2011</u>: Public hearing in Trenton.

<u>August 2011</u>: Public hearing in Pomona.

<u>August 2011</u>: Comments due.

LEGISLATIVE:

<u>**AMI Standards**</u>

<u>January 2010</u>: Introduction of a bill in 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. . . ."

March, May, and September 2010: Committed to and reported out of Assembly Telecommunications and Utilities Committee.

Bill to Define Efficiency and Conservation Programs Eligible to Meet EEPS to Include DR

September 2011: Bill introduced that would modify state code concerning an EEPS. The law in question says that the Board of Public Utilities (BPU) may adopt an "energy efficiency portfolio standard that may require each electric public utility to implement energy efficiency measures that reduce electricity usage in the State by 2020 to a level that is 20 percent below the usage projected by the board in the absence of such a standard. Nothing in this section shall be construed to prevent an electric public utility from meeting the requirements of this section by contracting with another entity for the performance of the requirements." As modified, the law would define "eligible energy efficiency and energy conservation programs" to include, among other things, demand response and load management.

December 2010: Bill reported out of Senate Environment and Energy Committee.

January 2011: Bill substituted by new language. The substitute language defined "eligible energy efficiency and energy conservation programs" as "programs subject to measurement and verification standards adopted by the board which create an EE certificate, and which utilize demand side management consisting of the management of customer consumption of electricity or of the demand for or generation of electricity through the implementation of (1) the deployment of energy efficiency technologies, management practices, or other strategies in residential, commercial, industrial, institutional, or government customers that reduce electricity consumption by those customers, (2) load management or demand response technologies, management practices 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, or (3) industrial by-product technologies consisting of the use of a by-product from an industrial process, including the reuse of energy from exhaust gases or other manufacturing by-products that are used in the direct production of electricity at the facility of a customer." The substitute language also included this clause:

> ". . . the board shall initiate a proceeding to evaluate energy efficiency portfolio standards, and after notice, provision of the opportunity for comment, and public hearing, may adopt such competitively neutral energy efficiency portfolio standards that require each electric power supplier and each basic generation service provider to purchase a specified number of EE certificates from eligible energy efficiency and energy conservation programs. The board shall permit an electric power supplier or basic generation service provider to satisfy the requirements of this subsection by participating in an energy trading program approved by the board in consultation with the Department of Environmental Protection."

New Mexico

REGULATORY:

New Mexico Transmission Report

July 2010: Governor Bill Richardson created the New Mexico Task Force on Statewide Electricity Transmission Planning.

November 2010: New Mexico Task Force on Statewide Electricity Transmission Planning issued its "New Mexico Electricity Transmission Planning Report."

The report doesn't address the smart grid at length, though it does mention it. It says, "Developing a high voltage transmission grid that addresses security and reliability issues while assisting renewable energy development will benefit the state by . . . preparing the state to take advantage of opportunities associated with new technologies such as electric vehicles and smart grids." Two other recommendations of note are:

- "Consider establishing RETA as the statewide independent transmission planning authority for all transmission lines greater than 240 kilovolts (kV) with at least 50 percent of the line intended for export of the power out-of-state. Since RETA is also a transmission project developer, potential conflict of interest issues would need to be addressed. This would require a statutory amendment."

- "With respect to transmission development cost-recovery for intrastate lines, it is recommended that the state bear a portion of the cost of developing lines intended to export power out-of-state in the interest of the economic development and job creation associated with constructing and operating both the transmission lines and the renewable energy projects enabled by the transmission lines. One option is to place a small transmission development assessment on electric customers' bills as is done elsewhere in the country. Note: Utilities and consumer advocacy groups opposed placing a transmission assessment on customers' bills."

LEGISLATIVE:

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

New York

REGULATORY:

Regulatory Policies for Smart Grid

July 2010: Commission commenced proceeding “to take a hard look at developing cutting-edge regulatory policies that will be needed to encourage the development of the smart grid and the overall modernization of the electric grid.” The initiating Order solicits comments in response to a list of questions. The questions fall under ten categories: (1) Vision for the Smart Grid Design; (2) Implementation Priorities; (3) Engaging Customers; (4) Benefit-Cost Analysis; (5) Cost Uncertainties; (6) Interoperability/Cyber-Security Standards; (7) Consumer Data Privacy/Access; (8) Communications; (9) Timing; and (10) Other.

The Commission’s initiating Order spelled out its position that modernizing the grid “supports important policy goals, including ensuring and enhancing system reliability, reducing greenhouse gas emissions, increasing energy efficiency and demand response, and expanding the use of renewable energy.” But it also noted the “sheer size and complexity of developing the ‘smart grid’” before explaining that if the realization of the smart grid isn’t “properly managed” there could be delays and disruptions costing billions of dollars. Yet, the Commission still encouraged utilities to propose smart grid projects in rate cases while it conducts its new smart grid proceeding.

The Commission directed all New York utilities to file comments and invited comments from other interested parties.

Finally, the Order closed an existing AMI proceeding, which the Commission opened in February 2009 to set minimum functional requirements for AMI systems and to begin a process for developing a "generic approach" to a cost-benefit analysis of AMI. That proceeding superseded and replaced two previous AMI proceedings and it also established minimum functional requirements for AMI systems and initiated a process for developing a “generic approach” to a cost-benefit analysis of AMI. Through it, the Commission approved proposals for projects developed by utilities in application for DOE smart grid grants funded under the American Recovery and Reinvestment Act 2009.

September 2010: Comments due.

October 2010: Reply comments due.

DOE Smart Grid Grants Proceeding

Background: In April 2009, the Commission initiated 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 it 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 2009, the Commission approved the utilities' proposals, provided that they receive DOE funding.

October 2010: Commission issued an Order granting Con Edison's request to establish a surcharge to recoup costs associated with deploying its DOE-funded smart grid project. In the same Order, the Commission denied similar requests of five other utilities that received Smart Grid Investment Grants—National Grid, Central Hudson Gas & Electric, Rochester Gas & Electric, New York State Electric & Gas, Orange & Rockland Utilities—and instead decided to allow them to recover expenses through a deferral mechanism. After receiving DOE grants, all six utilities filed proposals for surcharges in compliance with the Commission's Order "authorizing recovery of stimulus project costs."

November 2010: Con Edison filed a petition for reconsideration of the "two-prong test" the Commission established "to determine whether there would be 'double-recovery' of labor and labor related costs (such as fringe benefits) associated with the American Recovery and Reinvestment Act (ARRA) projects, particularly the Company's Smart Grid Demonstration Project (SGDP), and costs already allowed in rates under the 2010 Electric Rate Order."

April 2011: Commission issued Order granting Con Edison's petition for reconsideration and modifying the "two-prong test" for cost recovery.

New York Smart Grid Consortium

Background: In August 2009 Governor David Paterson launched the New York State Smart Grid Consortium. 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."

September 2010: The Smart Grid Consortium published its "Smart Grid Roadmap for the State of New York." The document analyzes "the relative costs, benefits, and priorities of the various smart grid technologies, business models, and policies in some detail including how different types of customers and geographic regions benefit." Its projections extend to the year 2025.

September 2010: The Smart Grid Consortium filed its "Smart Grid Roadmap for the State of New York" as comments in the Commission's proceeding "To Consider Regulatory Policies Regarding Smart Grid Systems and the Modernization of the Electric Grid."

Ongoing: The Smart Grid Consortium is periodically developing and distributing "articles, analysis and reports."

LEGISLATIVE:

Legislation Banning Market Clearing Prices in Wholesale Auctions

January 2009: 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."

January 2010: The legislation was referred to the Assembly's Corporations, Authorities and Commissions Committee.

June 2010: The legislation was referred to the Assembly's Ways and Means Committee.

North Carolina

REGULATORY:

Renewable Energy and Energy Efficiency Portfolio Standard (REPS)

August 2010: Commission issued an Order soliciting comments on questions regarding measurement and verification of utility programs designed to meet the state's renewable energy and energy efficiency portfolio standard (REPS). (The REPS was mandated by state law signed in August 2007 and 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).

October 2010: Comments due.

November 2010: Reply Comments due.

January 2011: Commission issued an Order amending REPS rules (Rules R8-64 through R8-69). Amended rules require utilities to report peak-demand reduction.

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:

Incentive Rate Structure

December 2010: The Commission opened a proceeding to review "whether modifications to Ohio's electric distribution utilities' rate structures would better align utility performance with Ohio's desired public policy outcomes." In its initiating Order, the Commission said that it "must also consider each electric utility's responsibility to achieve through efficiency programs energy savings of at least 22 percent by the end of the year 2025 and the obligation of each electric utility to serve 25 percent of its load by the year 2025 from an alternative energy resource, at least half of which must be renewable, including 0.5 percent from solar energy."

February 2011: Comments due. "This first round of comments is solely for the purpose of having parties aid the Commission in determining the appropriate questions and data necessary to be considered in this review. The Commission, at a later date, will consider and specify additional opportunities for input into this review."

Smart Grid and Data Access, Privacy Protection, and Cybersecurity

January 2011: Commission initiated proceeding to address (1) consumer privacy protection, (2) customer data access, (3) and cybersecurity "issues associated with distribution utility advanced metering and smart grid programs."

January 2011: Workshop to address privacy, data access, and cybersecurity relative to the NIST report, "Guidelines for Smart Grid Cyber Security."

February 2011: Commission issued an Order soliciting comments. Comments to address:

- "Whether the Commission should consider, develop, and adopt additional rules or policies or otherwise consider smart grid related privacy or data access issues at this time. . . ."

- “If the Commission considers smart grid related privacy and data access issues at this time, what process and procedures should be used to address. . . .”

March 2011: Comments due.

LEGISLATIVE:

Peak-Demand-Reduction Standard Clarification

February 2010: Bill introduced in the Ohio Senate.

May 2010: Ohio Senate passed legislation.

June 2010: Ohio House of Representatives passed legislation.

June 2010: Governor Ted Strickland signed the legislation. The new law amends the tax code relative to energy efficiency and renewable energy projects and modifies a loan program for alternative energy resources. It also clarifies that alternative energy resources supported by an “alternative energy revolving loan” may be used to meet Ohio’s energy-efficiency and peak-demand-reduction standards, which were established by Senate Bill 221 (signed in May 2008):

- “The act 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 act 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. In exchange for committing the savings or reduction, the mercantile customer may receive an exemption from an energy efficiency cost recovery mechanism permitted under the energy efficiency and peak demand reduction law.”

The new law says that 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 energy-efficiency and peak-demand-reduction standards created by Senate Bill 221 are (1) that efficiency programs must yield cumulative annual energy savings in excess of 22% by the end of 2025 and (2) that there must be a 1% demand reduction in 2009 and an additional 0.75% reduction each year thereafter through 2018.

Oklahoma

REGULATORY:

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

LEGISLATIVE:

Electric Utility Data Protection Act

January 2011: Legislation introduced in the Oklahoma House of Representatives that would set policy for the usage of electricity-consumption data.

May 2011: Bill passed by both House and Senate.

May 2011: Bill signed by Governor Mary Fallin. The enacted legislation, the Electric Usage Data Protection Act, has provisions for the following:

- “requiring an electric utility to provide certain access to and maintain the confidentiality of customer information”

- “authorizing certain use of customer-identifiable usage data without consent”
- “requiring an electric utility to provide standard usage data to a customer as a component of basic service”
- “requiring an electric utility to provide nonstandard usage data to a customer under certain circumstances”
- “authorizing disclosure of customer information to affiliates and certain third parties”
- “limiting disclosure to certain information”
- “specifying circumstances for the release of customer information to certain third parties”
- “providing for the use of aggregate usage data by an electric utility without consent”
- “authorizing the disclosure of aggregate usage data to a third party for certain purposes”
- “setting certain restrictions for the disclosure of aggregate usage data.”

Oregon

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

Pennsylvania

REGULATORY:

Implementation of Act 129

Background: This proceeding is the Commission's response to Pennsylvania Act 129, signed in October 2008, a law designed to reduce energy consumption and demand; to enhance default service procurement; and to expand alternative energy sources. It set a peak-demand reduction target of 4.5% and required electric distribution companies (with more than 100,000 customers) to develop smart meter deployment plans. The proceeding has been conducting through three phases.

In November 2008, the Commission Staff issued a draft proposal for an EE&C program.

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 June 2009, the Commission issued an Implementation Order adopting 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. EDCS filed their plans, and the Commission responded by announcing that it would consider each plan through a separate proceeding.

April 2010: Commission approved the "smart meter technology procurement and installation" plans filed by PPL, Met-Ed, Penelec, Penn Power, and Duquesne Light.

March 2011: Commission issued a Secretarial Letter directing EDCs to provide cost and savings data to the Act 129 Statewide Evaluator to enable the comparison of "the total costs for obtaining peak demand reductions with the total savings in energy and capacity costs to retail customers." The Act 129 Statewide Evaluator is to finalize the cost-benefit analysis by the end of November 2013. The analysis is to conclude with a "recommendation concerning the development of peak demand reduction targets, performance hours and future demand response protocols for 2013 and beyond." If benefits exceed costs, then the Commission "is to set additional incremental requirements for reduction in peak demand for the 100 hours of greatest demand or an alternative reduction approved by the Commission." The solicited data includes:

- "All capacity period hourly load data for each enrolled end use customer."
- "Identification of all load control events and notifications of each load control event for each enrolled customer, whether the customer participated in an individual demand response event or not."
- "For non-residential customers enrolled in Act 129 demand response programs, both Act 129 and PJM demand response events will be disclosed for each participant and for each hour of the event. A complete list of program participant summary data, including claimed demand response impacts by each participant, will be provided from which a sample set of participants will be selected for the provision of a complete data set."

April 2011: Commission issued Tentative Order seeking comments on a proposed "alternative approval process for minor Act 129 energy efficiency and conservation plan changes and the categories of changes that qualify for this alternative approval process." The proposal is meant to expedite a process that can take four months. The proposal would delegate to Commission Staff the authority to make the following minor changes:

- Elimination of a measure that is underperforming or has exhausted its budgeted amount.
- The transfer of funds from one measure to another measure within the same customer class.
- A change in the conditions of a measure, such as the addition of new qualifying equipment or a change in the rebate amount that does not increase the overall costs to that customer class.

April 2011: Comments due.

May 2011: Reply comments due.

Technical Reference Manual for Assessing EE & DR Energy Savings

November 2010: Commission issued a Tentative Order soliciting comments on the "proposed additions and updates" to the "Energy Efficiency and DSM Rules for Pennsylvania's Alternative Energy Portfolio Standard, Technical Reference Manual," which was originally adopted in June 2009. The Technical Reference Manual was adopted in effort to facilitate the assessment of "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. 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."

December 2010: Comments due on the proposed 2011 Technical Reference Manual.

January 2011: Reply comments due.

February 2011: Commission issued a Final Order adopting the updated 2011 Technical Reference Manual "to be applied beginning with the 2011-2012 AEPS Act and Act 129 EE&C program compliance years."

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.

Texas

REGULATORY:

Retail and Wholesale Markets and Smart Metering

Background: Since 2007 the Commission has been conducting this proceeding, which initially was a vehicle to consider 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. The proceeding features a working group, called the Advanced Metering Implementation Team (AMIT), which has been active through it.

April 2011: The Advanced Metering Implementation Team (AMIT) held a Stakeholder Steering Committee Meeting. The meeting featured presentations by subgroups and updates on CenterPoint's, AEP's, and Oncor's smart meter deployments.

May 2011: Commission released schedule of upcoming Advanced Metering Implementation Team (AMIT) meetings: May 2011; June 2011; July 2011; August 2011; and September 2011.

Smart Meter Evaluation

March 2010: Commission hired a consulting firm to test the accuracy of smart meters after Oncor's and TXU's customers began, in January 2010, to blame higher electric bills on their new smart meters.

August 2010: Commission announced that the results of a four-month investigation of smart meters by an independent consultant showed that the smart meters being deployed in Texas "are much more accurate than the ones they replace." The consulting firm, which filed its report with the Commission in July 2010, found that smart meters have an accuracy rate of 99.96% (5,625 were accurate and two were not), while traditional meters are 96% accurate. In addition to testing more than 5,600 smart meters, the consultant reviewed past test results for almost 1.1 million smart meters and over 86,000 electromechanical meters.

Increase Demand-Reduction Goal

November 2009: Commission initiated proceeding and called for the amendment of the current demand-reduction rule. The current demand-reduction target is that 20% of a utility's annual load growth for residential and commercial customers must be met by energy efficiency or demand response.

June 2010: Commission Staff recommended that the Commission change the current rule so as to set the demand-reduction goals at 30% in 2012, 40% in 2013, and 50% in 2014.

July 2010: Commission Chairman Barry Smitherman issued a memo recommending that the "Commission continue the measured and deliberate increase in energy efficiency goals over the next several years, while capping costs in a roughly proportional manner, also following the statutory increases." Specifically, he proposed that demand-reduction goals increase to 25% of growth in demand in 2012 and to 30% in 2013. He also proposed that costs caps for meeting the goals should be 150% of the 2010 program budget in 2012 and 200% of the 2010 budget in 2013. Utilities may meet the reduction goals through efficiency and/or demand response.

August 2010: Commission issued an Order adopting the amendment to energy efficiency and peak-demand reduction goals. As amended, the efficiency goal is 25% by 2012 and peak-demand reduction goal is 30% by 2013. The amended rule also includes "cost caps to minimize the impact of the higher goals on customers, who bear the costs of the program." Furthermore, it "updates the cost effectiveness standard by adjusting the avoided cost of capacity and the avoided cost of energy." Finally, "the amendment modifies the calculation of a performance bonus for an electric utility that exceeds its goal."

ERCOT Petition for More Emergency Interruptible Load Service Capacity

February 2011: ERCOT filed a Petition with the Commission requesting (1) the removal of the 90-day notice requirement for announcing changes to the Emergency Interruptible Load Service (EILS) Contract Period schedule and (2) the modification of the EILS Contract so as to enable additional EILS capacity procurement. More specifically, ERCOT sought an additional contract window for the two-month period between 4/1/11 and 5/31/11. This would enable it "to contract for additional EILS resources after deploying all resources for the maximum duration allowed under the rule during the load-shedding event" in February 2011. ERCOT said that adoption of the proposed rule would "avoid or minimize the imminent peril to the public health, safety, or welfare of the ERCOT Region community that could occur due to an emergency Load shedding event."

March 2011: Comments due.

March 2011: Reply comments due.

March 2011: Commission approved ERCOT request, issuing an Order adopting "on an emergency basis" amendments to the rules governing EILS.

LEGISLATIVE:

Legislation Allowing "Load Participation in All Energy Markets"

March 2011: Bill introduced in Texas Senate "relating to energy efficiency goals and programs, public information regarding energy efficiency programs, and the participation of loads in certain energy markets."

April 2011: Bill passed by Senate; introduced in House.

May 2011: Bill passed by House, engrossed, and sent to Governor Rick Perry.

May 2011: Govern Rick Perry signed the bill. The bill becomes effective in September 2011. Key provisions of the legislation are:

- The Texas Public Utility Commission is to adopt rules ensuring that ERCOT "allows load participation in all energy markets for residential, commercial, and industrial customer classes, either directly or through aggregators of retail customers, to the extent that load participation by each of those customer classes complies with reasonable requirements adopted by the organization relating to the reliability and adequacy of the regional electric network and in a manner that will increase market efficiency, competition, and customer benefits."

- With Commission approval, utilities may adopt "energy use programs with measurable and verifiable results that reduce energy consumption through behavioral changes that lead to efficient use patterns and practices."

- The energy-efficiency portfolio standard (EEPS) will increase, beginning in 2013, to 30% of a utility's annual load growth:

  3) each electric utility annually will provide, through market-based standard offer programs or through targeted market-transformation programs, incentives sufficient for retail electric providers and competitive energy service providers to acquire additional cost-effective energy efficiency, subject to cost ceilings established by the commission, for the utility's residential and commercial customers equivalent to:

  (A) not less than:
  (i) 30 percent of the electric utility's annual growth in demand of residential and commercial customers by December 31 of each year beginning with the 2013 calendar year; and
  (ii) the amount of energy efficiency to be acquired for the utility's residential and commercial customers for the most recent preceding year; and

(B) for an electric utility whose amount of energy efficiency to be acquired under this subsection is equivalent to at least four-tenths of one percent of the electric utility's summer weather-adjusted peak demand for residential and commercial customers in the previous calendar year, not less than:

(i) four-tenths of one percent of the utility's summer weather-adjusted peak demand for residential and commercial customers by December 31 of each subsequent year; and

(ii) the amount of energy efficiency to be acquired for the utility's residential and commercial customers for the most recent preceding year

Bill Establishing Storage as a "Generation Asset"

June 2011: Governor Rick Perry signed legislation establishing energy storage equipment and facilities as "generation assets." The new law directs the Texas Public Utility Commission to adopt or revise rules, as necessary, in order to implement it by January 2012. It also requires ERCOT to modify "protocols, standards, and procedures to implement this Act" by April 2012. The law reads:

SECTION 1. Subdivision (10), Section 31.002, Utilities Code, is amended to read as follows:

(10) "Power generation company" means a person that:

(A) generates electricity that is intended to be sold at wholesale, including the owner or operator of electric energy storage equipment or facilities to which Subchapter E, Chapter 35, applies. . . .

SECTION 2. Chapter 35, Utilities Code, is amended by adding Subchapter E to read as follows:

SUBCHAPTER E. ELECTRIC ENERGY STORAGE

Sec. 35.151. ELECTRIC ENERGY STORAGE. This subchapter applies to electric energy storage equipment or facilities that are intended to provide energy or ancillary services at wholesale, including electric energy storage equipment or facilities listed on a power generation company's registration with the commission or, for an exempt wholesale generator, on the generator's registration with the Federal Energy Regulatory Commission.

Sec. 35.152. GENERATION ASSETS. (a) Electric energy storage equipment or facilities that are intended to be used to sell energy or ancillary services at wholesale are generation assets.

(b) The owner or operator of electric energy storage equipment or facilities that are generation assets under Subsection (a) is a power generation company and is required to register under Section 39.351(a). The owner or operator of the equipment or facilities is entitled to:

(1) interconnect the equipment or facilities;

(2) obtain transmission service for the equipment or facilities; and

(3) use the equipment or facilities to sell electricity or ancillary services at wholesale in a manner consistent with the provisions of this title and commission rules applicable to a power generation company or an exempt wholesale generator.

(c) Notwithstanding Subsection (a), this section does not affect a determination made by the commission in a final order issued before December 31, 2010.

SECTION 3. Subdivision (10), Section 31.002, Utilities Code, as amended by this Act, and Subchapter E, Chapter 35, Utilities Code, as added by this Act, may not be construed to determine the regulatory treatment of electricity acquired to charge electric energy storage equipment or facilities and used solely for the purpose of later sale as energy or ancillary services.

Utah

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

Vermont

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

Virginia

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

Washington

REGULATORY:

Energy Independence & Security Act (EISA) 2007

Background: In March 2009, Commission opened proceeding to consider whether to adopt the four PURPA Standards created by the Energy Independence & Security Act (EISA) 2007. In September 2009, it issued an Order announcing 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. In December 2009 Commission issued Proposed Rule on the standard and solicited comments about it.

January 2010: Comments due.

February 2010: Public hearing.

March 2010: Final Order adopting set of rules requiring "each electric utility to submit periodic reports to the commission of the utility's evaluation of smart grid technologies that are available or likely soon to be available and any plans for implementing smart grid technologies." Each utility was directed to file a "smart grid technology report" in September 2010 and "a subsequent report no later than September 1st of each even-numbered year thereafter through September 2016."

LEGISLATIVE:

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

West Virginia

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

Wisconsin

REGULATORY:

Load Management, ARCs, & Governor's Task Force of Global Warming

Background: In April 2008, Commission began this 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, the Commission 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

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."

<u>February 2011</u>: Commission Staff issued a memo announcing that the proceeding will produce a demand response report that "will serve as an informational document for policy makers and utility personnel to consider as decisions are made with respect to demand response programs in the future." Furthermore, the memo explained that the Commission has partnered with the University of Wisconsin's Energy Analysis and Policy (EAP) graduate program for help developing the report. The EAP graduate students work as "consultants" with Staff, utilities, and other stakeholders.

<u>February – March 2011</u>: Commission meetings with the EAP students and other stakeholders to discuss "the interface of demand response and the wholesale market" and "impacts" of FERC's March 2011 Final Rule requiring ISOs and RTOs to pay full locational marginal price (LMP) for demand response resources (FERC Docket RM10-17).

<u>April 2011</u>: Commission Staff issued a memo announcing its expectation for a draft report to be issued later in April or May 2011.

May 2011: Commission published PPT presentation entitled "The Potential for Demand Response in Wisconsin," which it developed in collaboration with the University of Wisconsin—Madison

Wisconsin Commission Issues Biennial Strategic Energy Assessment

February 2011: Commission published its sixth biennial Strategic Energy Assessment. The February 2011 report, "Strategic Energy Assessment: Energy 2016," says that peak demand is growing at a slower rate due to the "economic downturn." In 2010, for example, utilities projected peak demand to grow at 2.75%. Between 2011 and 2016, however, the Commission now predicts that it will grow at 1% per year.

Wyoming

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