

REPORT OF THE DEMAND-SIDE RESOURCES & SMART GRID COMMITTEE

This report summarizes a selection of legislative, regulatory, and judicial developments at the federal and state level in the areas of Smart Grid, demand response, and energy efficiency during 2010.*

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I. SMART GRID DEVELOPMENTS

A. Federal Activity

1. National Institute of Standards and Technology and FERC

In 2010, the National Institute of Standards and Technology (NIST) and the Federal Energy Regulatory Commission (FERC) took steps to fulfill a joint statutory mandate to develop Smart Grid interoperability standards. The Energy Independence and Security Act of 2007 (EISA),¹ which lays out the policy of the United States with regard to modernization of the nation's electricity transmission and distribution system, mandates the development of a framework to achieve interoperability of Smart Grid devices and systems, including protocols and model standards for information management.² The EISA directs the NIST to coordinate the development of this framework and directs the FERC, once it is satisfied that the NIST's work has led to "sufficient consensus" on interoperability standards, to "institute a rulemaking proceeding to adopt such standards and protocols."³

In January 2010, the NIST released a framework and roadmap that identified a number of standards that are applicable to the ongoing development of the Smart Grid.⁴ In October 2010, after further discussion with stakeholders and an analysis of the standards' cyber security protections, the NIST identified five suites of standards that it stated were ready for consideration by regulatory authorities.⁵

The standards and their functions are:

- IEC 61970 and IEC 61968: Providing a Common Information Model (CIM) necessary for exchanges of data between devices and networks, primarily in the transmission (IEC 61970) and distribution (IEC 61968) domains;
- IEC 61850: Facilitating substation automation and communication as well as interoperability through a common data format;
- IEC 60870-6: Facilitating exchanges of information between control centers;

1. Energy Independence and Security Act of 2007 (EISA), Pub. L. No. 110-140, 121 Stat. 1492 (2007).

2. EISA § 1305(a) (to be codified at 15 U.S.C. § 17385(a)).

3. *Id.* § 1305(d) (to be codified at 15 U.S.C. § 17385(d)).

4. NIST, U.S. DEP'T OF COMMERCE, NIST FRAMEWORK AND ROADMAP FOR SMART GRID INTEROPERABILITY STANDARDS, RELEASE 1.0, NIST SPECIAL PUBLICATION 1108 (Jan. 2010), available at http://www.nist.gov/public_affairs/releases/upload/smartgrid_interoperability_final.pdf.

5. NIST Identifies Five "Foundational" Smart Grid Standards, NIST (Oct. 7, 2010), http://www.nist.gov/public_affairs/releases/smartgrid_100710.cfm.

- IEC 62351: Addressing the cyber security of the communication protocols defined by the preceding IEC standards.⁶

The FERC responded to the NIST announcement by stating that while it had made no determination yet on whether “sufficient consensus” exists for these standards, it was establishing a docket, RM11-2-000, for a possible rulemaking proceeding pursuant to EISA section 1305(d).⁷ The FERC stated that it would issue a Notice of Proposed Rulemaking for comment before adopting any of the five suites of standards identified by the NIST.⁸ The FERC stated that while the EISA does not authorize the FERC to require compliance with the final standards, it might consider requiring compliance with the standards under its Federal Power Act authorities.⁹ In November 2010, the FERC convened a technical conference on Smart Grid Interoperability Standards and in December 2010 the FERC announced a planned technical conference in January 2011 to obtain further information to aid the FERC’s determination of whether there is “sufficient consensus” that the five NIST families of standards are ready for FERC consideration in a rulemaking proceeding.¹⁰

2. Federal Communications Commission

a. National Broadband Plan

The Federal Communications Commission (FCC) has prescribed timelines for state and government agencies to process applications for authority to construct and attach wireless communications, or broadband, equipment on public utility towers.¹¹ The FCC has gone further in issuing a document entitled, “Connecting America: The National Broadband Plan” (National Broadband Plan),¹² which details steps to increase access by network providers to poles, conduits, ducts, and rights-of-way. Under the National Broadband Plan, the FCC intends to set: (1) lower and more uniform rates for pole attachments; (2) a timeline for each step of the pole attachment process, including dispute resolution, to be backed up with damage award authority if so enacted by Congress; (3) procedures for improved dissemination of information on the availability of poles, ducts, conduits, and rights-of-way; and (4) a joint task force with state, tribal, and local policymakers to provide guidelines for rates and

6. *Id.*

7. Press Release R-11-01, FERC, FERC Takes First Step in Smart Grid Rulemaking Process, Docket No. RM11-2-000 (Oct. 7, 2010), available at <http://www.ferc.gov/media/news-releases/2010/2010-4/10-07-10.pdf>.

8. *Id.*

9. *Id.*

10. Notice of Technical Conference, *Smart Grid Interoperability Standards*, Docket No. RM11-2-000, FERC (Dec. 21, 2010), available at <http://www.ferc.gov/EventCalendar/Files/20101221145852-RM11-2-000TC.pdf>.

11. Declaratory Ruling, *Petition for Declaratory Ruling to Clarify Provisions of Section 332(c)(7)(B) to Ensure Timely Siting Review and to Preempt Under Section 253 State and Local Ordinances that Classify All Wireless Siting Proposals as Requiring a Variance*, Wt Docket No. 08-165 (FERC Aug. 14, 2008).

12. FCC, CONNECTING AMERICA: THE NATIONAL BROADBAND PLAN, CHAPTER 6, “INFRASTRUCTURE,” at 107-118, available at <http://download.broadband.gov/plan/national-broadband-plan-chapter-6-infrastructure.pdf>.

terms and conditions of access to public rights-of-way.¹³ The National Broadband Plan also recommends that: (1) Congress provide the FCC increased jurisdiction by removing exemptions from FCC requirements for states that adopt their own system of regulation and for co-operatives, municipalities, and non-utilities, and provide statutory provisions on access to poles, ducts, conduits, and rights-of-way, as well as authority for federal agencies to set fees for access to federal rights-of-way, and “dig once” requirements for federally funded projects along rights-of-way; (2) the Executive Branch develop master contract terms for placing wireless towers on federal government property; and (3) the Department of Transportation place a condition on funding of transportation projects to states and localities, requiring them to allow qualified parties to jointly deploy conduits.¹⁴

The FCC’s stated reason for taking these actions is concern that the rental rates for pole attachments vary widely by whether an entity is a cable operator, telecommunications company, or incumbent local exchange carrier, and whether the broadband attachment is serving a rural or urban area.¹⁵ Standardization of the process for moving wires attached to a pole to accommodate spacing of equipment according to electric and safety codes is also seen by the FCC as a cost-saving measure.¹⁶ The FCC seeks to expedite the entire process of effectuating communications attachments to utility equipment and property. Achievement of a streamlined, easily searchable data system for sharing essential infrastructure information among pole owners and pole attachers is another goal of the FCC.¹⁷

In furtherance of the National Broadband Plan, the FCC, on May 20, 2010, issued an “Order and Further Notice of Proposed Rulemaking”¹⁸ (FCC Broadband Order), in which the FCC issued five final rules and proposed thirty-two new or revised rules pertaining to rights and obligations of pole owners and communications companies attaching to utility poles. By final rule, the FCC ordered pole owners to allow attachers to use the same engineering methods employed by the utilities to perform attachments, and to allow timely access to poles, including timely preparation of poles for attachments.¹⁹ The proposed rules include timelines for the conducting of surveys, estimates, attacher acceptance, performance, and multiparty coordination.²⁰ They also include proposed procedures for use of outside contractors, payment schedules, data dissemination, dispute resolution procedures, remedies, and enforcement mechanisms for unauthorized attachments.²¹ In addition, the FCC Broadband Order sets forth for comments a series of questions on various rate issues.²²

13. *Id.* at 127.

14. *Id.*

15. *Id.*

16. *Id.*

17. *Id.*

18. Proposed Rulemaking, Implementation of Section 224 of the Act; A National Broadband Plan for Our Future, 75 Fed. Reg. 41,338 (2010) (to be codified at 47 C.F.R. pt. 1).

19. *Id.*

20. *Id.*

21. *Id.*

22. *Id.*

Commenters filed the last round of comments in response to the FCC Broadband Order on October 4, 2010.²³

b. “White Space” Spectrum for Smart Grid Applications

On September 23, 2010, the FCC approved an order establishing new rules for unlicensed use of “white space” radio spectrum (FCC White Space Order).²⁴ White space refers to unused frequencies between those used for television broadcast channels. The white space in the UHF and VHF bands became available with the transition from analog to digital television. The FCC initially approved the use of this spectrum in an order issued in November 2008²⁵ and, in the National Broadband Plan, recommended that rules to allow for use of television white spaces be established expeditiously.²⁶

While some telecommunications providers are eyeing the 300 to 400 MHz of newly available spectrum for wireless mobile broadband services, the spectrum is also considered an option for certain Smart Grid applications.²⁷ The FCC approved the use of the white spaces for both fixed and mobile communications devices.²⁸ The spectrum has very favorable propagation characteristics (e.g., the radio signals on these frequencies can travel for long distances and can penetrate walls and other obstructions), making it attractive for “super Wi-Fi” as well as some utility applications, particularly where difficult terrain makes wireless communications operating on other frequencies problematic.

Plumas-Sierra Electric Cooperative & Telecommunications in the Sierra-Nevada Mountains of California became the first electric utility to use white spaces to establish broadband connectivity to its remote substations, for SCADA and switchgear communications, and to provide consumers with real-time energy consumption data online.²⁹ Plumas-Sierra is also using the spectrum to provide Wi-Fi broadband services to an underserved community.³⁰

The rules set forth in the FCC White Space Order³¹ establish, in relevant part:

- Criteria to protect incumbent authorized services;
- Technical rules for devices operating in the television spectrum bands;
- Requirements for a television bands database; and

23. *Id.*

24. Second Memo Opinion and Order, *In re Unlicensed Operation in the TV Broadcast Bands 04-186; Additional Spectrum for Unlicensed Devices Below 900 MHz and in the 3 GHz Band 02-380* (FCC Sept. 23, 2010).

25. Second Report and Order and Memorandum Opinion and Order, *In re Unlicensed Operation in the TV Broadcast Bands 04-186; Additional Spectrum for Unlicensed Devices Below 900 MHz and in the 3 GHz Band* (Nov. 14, 2008).

26. Recommendation 5.12, *Connecting America: The National Broadband Plan*, available at <http://www.broadband.gov/plan>.

27. *Id.*

28. *Id.*

29. *Id.*

30. *Id.*

31. Final Rulemaking, *Unlicensed Operation in the TV Broadcast Bands*, 75 Fed. Reg. 75,814 (2010) (to be codified at 47 C.F.R. pts 0 & 15).

- Specification of the channels that can be used by television bands devices.

To avoid interference with others using the television spectrum airwaves, the rules require that communications devices operating in the television bands have the capability to query a new database for available channels before the devices transmit a signal.³² Further, the device must re-check the database at least daily.³³

3. Department of Energy

In response to the recommendations of the FCC in the National Broadband Plan that the Department of Energy (DOE) should study and report upon (1) how Smart Grid technologies were likely to affect the communications needs of electric utilities, and (2) the consumer-privacy and data-security implications of Smart-Grid technologies, the DOE's Office of General Counsel, published two Requests for Information (RFIs) outlining public comment-and-hearing processes.³⁴ These processes are intended to allow interested parties the opportunity to ensure that all available perspectives and data had informed the DOE's analyses of these two critical issues.³⁵ The DOE then held separate public roundtables on communications needs and data privacy during June 2010, and by August 2010, it had solicited and received 100 comments and reply comments in these two proceedings.³⁶ DOE staff then reviewed the resulting records, compiled the results, and on October 5, 2010, published two reports: (1) *Data Access and Privacy Issues Related to Smart Grid Technologies* (Data Privacy Report), and (2) *Communications Requirements of Smart Grid Technologies* (Communication Requirements Report).³⁷

Each of these reports made a series of recommendations. The Data Privacy Report acknowledged that state and local governments should still play leading roles in deploying Smart Grid technologies and regulating consumer privacy by stressing the important benefits that such technologies could provide to low-income consumers and by proposing ways to avoid the duplicative or conflicting requirements that could delay the growth of responsible third-party energy management services.³⁸ The Communications Requirements Report concluded that efforts to deploy Smart Grid technologies and modernize our electrical grid

32. *Id.*

33. *Id.*

34. Dep't of Energy, Implementing the National Broadband Plan by Empowering Consumers and the Smart Grid: Data Access, Third Party Use, and Privacy, 75 Fed. Reg. 26,203 (2010); Dep't of Energy, Implementing the National Broadband Plan by Studying the Communication Requirements of Electric Utilities to Inform Federal Grid Policy, 75 Fed. Reg. 26,206 (2010).

35. *Id.*

36. NIST, DEP'T OF ENERGY, SMART GRID INTEROPERABILITY PANEL, CYBER SECURITY WORKING GROUP, GUIDELINES FOR SMART GRID CYBER SECURITY: VOL. 2, PRIVACY AND THE SMART GRID, NISTIR 7628 (Aug. 2010), available at http://csrc.nist.gov/publications/nistir/ir7628/nistir-7628_vol2.pdf.

37. *Data Access and Privacy Issues Related to Smart Grid Technologies* (Oct. 5, 2010), available at http://www.gc.energy.gov/documents/Smart_Grid_Communications_Requirements_Report_10-05-2010.pdf; *Communications Requirements of Smart Grid Technologies* (Oct. 5, 2010), available at http://www.gc.energy.gov/documents/Broadband_Report_Data_Privacy_10_5.pdf [hereinafter *Communications Requirements of Smart Grid Technologies*].

38. *Communications Requirements of Smart Grid Technologies*, *supra* note 37.

required electrical utilities to be broadly included in most of the private/public advisory committees that help shape overall federal communications policy.³⁹

In September 2010, the DOE issued its third Smart Grid RFI, in which it sought input on how to define:

“smart grid” for policymaking purposes; consumer-level benefits from, and challenges to, smart grid deployment; benefits and challenges associated with smart grid implementation on the “utility side” of the meter; [how] policy makers at all levels of government can share experience and resources; and the broader, economy-wide benefits and challenges associated with the smart grid.⁴⁰

Comments on this latest RFI were due on November 1, 2010.⁴¹

4. Other Federal Developments

a. National Science and Technology Council Committee on Technology

In July 2010, the National Science and Technology Council (NSTC) Committee on Technology established a Subcommittee on Smart Grid.⁴² The Subcommittee was formed to establish an interagency process that will further the Administration’s energy goals and the American Recovery and Reinvestment Act (ARRA).⁴³ Specifically, the Subcommittee on Smart Grid will provide policy recommendations and guidance for development of the administration’s Smart Grid policy.⁴⁴ The Subcommittee includes representatives from the Department of Agriculture, Department of Commerce, Department of Homeland Security, National Economic Council, Office of Management and Budget, and Office of Science and Technology Policy.⁴⁵ Its co-chairs are Patricia Hoffman, DOE Assistant Secretary for the Office of Electricity Delivery and Energy Reliability, and George Arnold, Deputy Director for Technology Services and National Coordinator for Smart Grid Interoperability at the National Institute of Standards and Technology.⁴⁶ Following a series of outreach meetings with stakeholders in 2010, the subcommittee is anticipated to issue a report in early 2011 that will articulate a vision for the Smart Grid, provide analysis of the social costs, benefits, and issues related to the Smart Grid, identify barriers to Smart Grid deployment, and make policy recommendations for federal, state, and local policymakers to overcome those barriers.⁴⁷ The White House sees the Subcommittee on Smart Grid of the NSTC Committee on Technology as a standing subcommittee that will have “an ongoing mandate to catalyze, support, and elevate the quality of the government’s involvement in the Smart Grid.”⁴⁸

39. *Id.*

40. Dep’t of Energy, Addressing Policy and Logistical Challenges to Smart Grid Implementation, 75 Fed. Reg. 57,006 (2010).

41. *Id.*

42. *National Science and Technology Council Establishes Subcommittee on Smart Grid*, July 12, 2010, http://www.smartgrid.gov/news/nstc_subcommittee (last updated July 13, 2010).

43. *Communications Requirements of Smart Grid Technologies*, *supra* note 37.

44. *Id.*

45. *Id.*

46. *National Science and Technology Council Establishes Subcommittee on Smart Grid*, *supra* note 42.

47. *Id.*

48. *Id.*

b. Internal Revenue Service

In March 2010, the Internal Revenue Service (IRS) provided a safe harbor under section 118(a) of the Internal Revenue Code (the Code) for the treatment of Smart Grid Investment Grants (SGIG) made to corporations by the DOE for qualifying investments as authorized by the EISA.⁴⁹ This means that the IRS will not challenge the exclusion of a SGIG from a corporation's gross income, so long as the corporation reduces the basis of its property as required under section 362(c)(2) of the Code.⁵⁰ The safe harbor only applies to SGIGs made to corporate taxpayers by DOE under 42 U.S.C. § 17386, not those made to non-corporate taxpayers, or those made under 42 U.S.C. § 17384 (Smart Grid technology, research, development, and demonstration).⁵¹

B. State Activity

Several studies were issued by the Institute for Electric Efficiency (IEE) and a Report to the Texas Legislature by the Public Utility Commission of Texas (PUC) on the implementation of smart grid and/or energy efficiency programs in the 2007-2010 time period.⁵² For example, in its *Report to the 82nd Texas Legislature – A Report on Advanced Metering as Required by House Bill 2129*, the PUC advised that 2 million smart meters will have already been installed in Texas by the close of 2010, and that 16 million have been installed nationwide.⁵³ In *Moving Toward Utility-Scale Deployment of Dynamic Pricing in Mass Markets*, IEE states that more than thirty states have started or announced plans for smart meter deployment.⁵⁴ More specific state Smart Grid developments in 2010 are discussed below.

1. California

The state's Smart Grid statute, passed in 2009, required the California Public Utilities Commission (CA PUC) to develop an overarching plan for smart grid deployment.⁵⁵ By decision issued on June 24, 2010, the CA PUC provided a roadmap of issues the utilities must address in their plans in order to bring the best results at the lowest possible cost to consumers, including:⁵⁶

49. Examination of Returns and Claims for Refund, Credit, or Abatement: Determination of Correct Tax Liability, 26 C.F.R. § 601.105 (2010).

50. *Id.*

51. *Id.*

52. PUC, REPORT TO THE 82ND TEXAS LEGISLATURE – A REPORT ON ADVANCED METERING AS REQUIRED BY HOUSE BILL 2129 at 4 (Sept. 2010), available at http://www.puc.state.tx.us/electric/reports/AMS/Commission_Report_on_Advanced_Metering_2010.pdf.

53. *Id.*

54. IEE, MOVING TOWARD UTILITY-SCALE DEPLOYMENT OF DYNAMIC PRICING IN MASS MARKETS 30 (June 2009), available at http://www.edisonfoundation.net/iee/reports/IEE_Utility-ScaleDynamicPricing_0609.pdf. The Whitepaper discusses “dynamic” and “time-of-use” pricing that may be adopted once smart meters and necessary communication systems are in place, and particularly the peak load reduction achieved from pilot and to date from wide-scale implementation programs for this hardware and related pricing. The expected and observed benefits and costs of such programs are also discussed.

55. 2009 Cal. Legis. Serv. 327 (LexisNexis); CAL. PUB. UTIL. CODE § 8360 (West 2009).

56. *Decision Adopting Requirements for Smart Grid Deployment Plans Pursuant to Senate Bill 17 (Padilla)*, Chapter 327, Statutes Of 2009, RM-08-12-009, 2010 Cal. PUC LEXIS 233 (Cal. Pub. Utils. Comm'n June 28, 2010).

- a vision statement to orient utilities to meet today's requirements and tomorrow's needs;
- a strategy to consider whether using existing communications infrastructure can reduce deployment costs;
- a security and cyber security strategy to ensure these are considered at the planning stage;
- cost estimates of technologies and infrastructure investments a utility expects to make in the next five years, along with provisional cost ranges for the following five years; and
- metrics permitting the assessment of progress.

Each of the state's utilities is required to file Smart Grid Deployment Plans by July 1, 2011.⁵⁷

In September 2010, California's Governor signed SB 1476, protecting customers' energy consumption data from disclosure by utilities and by authorized third parties or utility contractors.⁵⁸ The statute also prohibits utilities with Smart Grid platforms that permit customers to access energy consumption data from making such customer access contingent upon a customer's consent to disclosure of personally identifiable information to a third party.⁵⁹

On April 6, 2010, the EMF Safety Network filed an application with the CA PUC asking to reopen its review of Smart Meters and require Pacific Gas & Electric Company (PG&E) to demonstrate that its advanced meter program is consistent with delivery of safe, reliable gas and electric service at reasonable rates.⁶⁰ The Commission denied EMF Safety Network's request in a decision signed on December 2, 2010, based on the fact that "[t]he radio frequency (RF) emissions from Smart Meters . . . are [1/6000] 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."⁶¹

A lawsuit filed against PG&E in 2009, alleging that the utility falsely advertised its Smart Meter program and benefited from unfair competition, resulting in steeply increased rates for certain consumers, remained pending in California Superior Court during 2010.⁶²

2. Colorado

In October 2010, a Colorado Public Utilities Commission (Col. PUC) Administrative Law Judge (ALJ) issued a Recommended Decision that the Col. PUC approve a Certificate of Public Convenience and Necessity to Public

57. *Id.*

58. 2010 Cal. Legis. Serv. 497 (LexisNexis) (S.B. 1476).

59. *Id.*

60. *Application of EMF Safety Network for Modification of D.06-07-027 and D.09-03-026*, No. A10-04-018 (Cal. Pub. Utils. Comm'n Apr. 6, 2010).

61. Decision Granting Motion of Pacific Gas and Electric Company to Dismiss Application, No. A10-04-018, 2010 Cal. PUC LEXIS 534 (Cal. Pub. Utils. Comm'n Dec. 2, 2010).

62. *Flores v. Pac. Gas & Electric Co.*, No. S-1500-CV-268647 (Cal. Super. Ct. 2010), available at <http://mmidl.com/sgt/2010-Feb-09/FLORES%20-%20Opposition%20to%20the%20Demurrer.pdf>.

Service Company of Colorado for its SmartGridCity™ project.⁶³ The ALJ also authorized Public Service Company of Colorado to recover approximately \$45 million in costs related to the project.⁶⁴ SmartGridCity™ is one of several large scale, comprehensive Smart Grid pilot projects already in operation. It includes smart meters, a grid communication system, and appliance switches and other hardware to assist consumers in energy conservation. The Col. PUC, in directing hearings on the Application, “expressed its belief that the smart grid concept holds great promise,” and defined nine issues for examination including cost/benefit, dynamic pricing, and extent of effectiveness in expanding conservation.⁶⁵ Colorado has also opened two additional dockets to examine Smart Grid issues unrelated to this pilot project.⁶⁶

3. District of Columbia

In December 2009, the Public Service Commission of the District of Columbia (DCPSC) authorized Potomac Electric Power Company (PEPCO) to proceed with an Advanced Metering program and to establish a regulatory asset to recover its non-grant funded costs as permitted by action of the D.C. Council.⁶⁷ The DCPSC noted that PEPCO had been granted approximately \$45 million in federal funds to pursue its AMI and that the magnitude of that grant was sufficient to render the proposed program cost-effective.⁶⁸ Under the planned program, PEPCO will begin installation of the meters in Fall 2010.⁶⁹ PEPCO will initially conduct a dynamic pricing pilot program, and then all customers will receive the new meters and pricing.⁷⁰ During 2010, the DCPSC issued additional Orders establishing the process for review of the accuracy of and for approval of the specific meters selected for installation, and for approval of PEPCO’s dynamic pricing pilot program.⁷¹

4. Hawaii

In July 2010, the Hawaii Public Utilities Commission (HI PUC) denied the application of the Hawaiian Electric Company, Inc., and affiliated utility

63. *In the Matter of the Application of Public Service Company of Colorado for an Order Approving SmartGridCity CPCM*, No. 10A-12E, 2010 Colo. PUC. LEXIS 1177 (Colo. Pub. Utils. Comm’n Oct. 27, 2010) (Recommended Decision).

64. *Id.*

65. *In the Matter of the Investigation of Issues Related to Smart Grid and Advanced Metering Technologies*, No. 1010-099EG, 2010 Colo. PUC LEXIS 153 (Colo. Pub. Utils. Comm’n Feb. 24, 2010).

66. *Id.*

67. *In the Matter of the Application of PEPCO for Authority to Establish a Demand Side Management Surcharge and an Advance Metering Infrastructure Surcharge*, 278 P.U.R. 4th 155, 2009 WL 5048995 (D.C. Pub. Serv. Comm’n Dec. 17, 2009).

68. *Id.*

69. *Id.*

70. *Id.*

71. *Id.*; *In the Matter of the Application of Potomac Electric Power Company for Authorization to Establish a Demand Side Management Surcharge*, No. 1056, 2010 D.C. PUC LEXIS 79 (D.C. Pub. Serv. Comm’n Mar. 8, 2010); *In the Matter of the Application of Potomac Electric Power Company for Authorization to Establish a Demand Side Management Surcharge*, No. 1056, 2010 D.C. PUC LEXIS 332 (D.C. Pub. Serv. Comm’n Sept. 22, 2010); *In the Matter of the Investigation into the Potomac Electric Power Company’s Non-AMI Demand Response Program Plan*, No. 1070, 2010 D.C. PUC LEXIS 462 (D.C. Pub. Serv. Comm’n Dec. 20, 2010). PEPCO’s request for cost-recovery through a surcharge was denied.

companies (together, the HECO Companies) for approval of recovery of costs associated with Smart Grid development and deployment.⁷² The HI PUC determined that the HECO Companies had not demonstrated sufficient benefits for ratepayers necessary to justify the requested investments in technology testing, but invited the HECO Companies to return with a more comprehensive plan.⁷³ This decision put an end to the HECO Companies' broader plan for a \$155 million smart meter deployment plan.⁷⁴

5. Illinois

In 2008, the Illinois Commerce Commission (Illinois Commission) approved a \$274 million rate increase for Commonwealth Edison Company (Com. Edison) that included, among other elements, a separate rider that permitted Com. Edison to immediately recoup costs associated with its investment in advanced metering infrastructure (AMI Rider).⁷⁵ A number of parties appealed certain elements of the Illinois Commission's order.⁷⁶ The Illinois Appellate Court, 2nd District, affirmed in part and reversed in part and remanded the case to the Illinois Commission.⁷⁷ In relevant part, the Court held that the Illinois Commission erred in approving the AMI Rider because it violated the rule against single-issue ratemaking that is not justified by any special circumstances.⁷⁸ Based on several Illinois precedents, the Court concluded that such a rider is permitted only "if (1) the cost is imposed upon the utility by an external circumstance over which the utility has no control and (2) the cost does not affect the utility's revenue requirement."⁷⁹ The AMI rider approved by the Illinois Commission failed to pass this test because Com. Edison had proposed the rider "precisely because the improvements are expected to reduce other expenses and increase income in the long term, which affects the utility's revenue requirement."⁸⁰

6. Maryland

The Maryland Public Service Commission (Md PSC) issued an order on August 13, 2010, approving a Smart Grid initiative submitted by Baltimore Gas and Electric Company (BGE).⁸¹ The Md PSC authorized BGE to create a regulatory asset, structured to avoid loss of earnings.⁸² However, the Md PSC stated that BGE must demonstrate cost effectiveness prior to seeking cost

72. *In the Matter of the Application of Hawaiian Electric Company, Inc.*, No. 2008-0303, 2010 Haw. PUC LEXIS (Haw. Pub. Utils. Comm'n July 26, 2010) (Order Closing Docket).

73. *Id.*

74. *Id.*

75. Order, *Commonwealth Edison Company: Proposed General Increase in Electric Rates*, No. 07-0566 (Ill. Commerce Comm'n Sept. 10, 2008).

76. Notice of Appeal, *Commonwealth Edison Company: Proposed General Increase in Electric Rates*, No. 07-056 (Ill. Commerce Comm'n Oct. 17, 2008).

77. *Commonwealth Edison Co. v. Ill. Commerce Comm'n*, 2010 Ill. App. LEXIS 1057 (Sept. 30, 2010).

78. *Id.*

79. *Id.* at 53.

80. *Id.* at 55.

81. Order No. 83531, *In the Matter of the Application of Baltimore Gas and Electric Company*, No. 9208 (Pub. Serv. Comm'n of MD 2010).

82. *Id.*

recovery and postponed the issue of the cost recovery of legacy meters to a future depreciation proceeding.⁸³ BGE was instructed to work with other stakeholders to develop a customer education plan, to be submitted for approval, and to work with the parties in developing and submitting a set of metrics to be used to monitor project development.⁸⁴

The Md PSC also approved PEPCO's Smart Grid project, with conditions,⁸⁵ while rejecting the Smart Grid application of Delmarva Power and Light Company (Delmarva) pending filing by Delmarva of a revised business case.⁸⁶ The Md PSC also ordered BGE and PEPCO to synchronize their approach to Dynamic Pricing.⁸⁷ Both BGE and PEPCO are currently participating in stakeholder working groups to build alignment concerning proposed metrics and Customer Education and Communications planning.⁸⁸ Both utilities have also qualified for partial funding of their Smart Grid projects from the DOE.⁸⁹

7. Oklahoma

In June 2010, the Oklahoma Corporation Commission (OK Commission) approved a Joint Stipulation and Settlement Agreement between Oklahoma Gas and Electric Company (OG&E), the Public Utility Division of the Commission, the Office of the Attorney General, the OG&E Shareholders Association, and the Oklahoma Industrial Energy Consumers relating to OG&E's system-wide Smart Grid deployment (the Settlement Agreement).⁹⁰ The Settlement Agreement requests that the OK Commission grant OG&E's Smart Grid deployment approval request and authorize recovery of associated costs, subject to conditions set forth in the Settlement Agreement.⁹¹ Those conditions include a cap on Smart Grid project costs that will automatically be included in the rate base of \$366.4 million, with OG&E having the right to offer evidence during its 2013 rate case to establish that any costs incurred over that amount were prudently incurred.⁹² The Settlement Agreement also provided for customer education on the part of OG&E and a pass-through to customers of certain cost reductions expected to result from the Smart Grid deployment.⁹³

83. *Id.*

84. *Id.*

85. Order No. 83571, *In the Matter of the Application of Potomac Electric Power Company and Delmarva Power & Light Company*, No. 9207 (Pub. Serv. Comm'n of Md. 2010); Order No. 83532, *In the Matter of the Application of Potomac Electric Power Company and Delmarva Power & Light Company*, No. 9207 (Pub. Serv. Comm'n of Md. 2010).

86. Order No. 83571, *In the Matter of the Application of Potomac Electric Power Company and Delmarva Power & Light Company*, No. 9207, at 57 (Pub. Serv. Comm'n of Md. 2010).

87. *Id.* at 1.

88. *Id.*

89. *Advanced Metering Infrastructure*, SMARTGRID.GOV, http://www.smartgrid.gov/smartgrid_projects?order=field_total_value_value&sort=desc&category=4 (last visited Feb. 15, 2011).

90. Final Order Approving Joint Stipulation and Settlement Agreement, Order No. 576595, *In the Matter of the Application of Oklahoma Gas and Electric Company*, No. PUC 2010000029 (Okla. Corp. Comm'n June 22, 2010).

91. Joint Stipulation and Settlement Agreement, *In the Matter of the Application of Oklahoma Gas and Electric Company*, No. PUD 2010000029, at 2 (Okla. Corp. Comm'n May 27, 2010).

92. *Id.* at 3.

93. *Id.*

8. Pennsylvania

In 2008, the Pennsylvania General Assembly adopted Act 129 which requires, among other matters, that electricity distribution companies with more than 100,000 customers develop smart meter installation plans and energy efficiency and conservation plans, the latter to meet specified energy and peak load conservation goals, and obtain their approval by the Pennsylvania Public Utility Commission (PAPUC).⁹⁴ Since the Act's passage, the PAPUC has aggressively implemented it. In Spring 2010, after a hearing process and based largely upon settlements between utilities and interested stakeholders, the PAPUC approved the smart metering plans of six of the seven utilities to which this requirement of Act 129 applies.⁹⁵ Although individual plans differ, each generally provides for a thirty month period (i.e., the grace period permitted by Act 129) to evaluate different technologies, install and operate meters and related communication systems on a pilot basis, educate customers, implement dynamic pricing pilots, and prepare final plans for roll-out to all customers, followed by universal installation within fifteen years as required by the statute.⁹⁶ The PAPUC also approved a cost-recovery mechanism for all program related costs (generally an automatic adjustment clause with true-up procedure).⁹⁷ In addition, the PAPUC approved specific terms for access by competitive energy suppliers to data generated by the new meters.⁹⁸ The cost of full plan implementation is generally three to five hundred million dollars.⁹⁹ As much as 50% of these costs have been offset by an ARRA grant.¹⁰⁰ In Fall 2010, the PAPUC reviewed and approved modifications to four utilities' energy efficiency and conservation plans and approved for the first time the plan of West Penn Power Company¹⁰¹ On October 28, 2010, PECO Energy filed a petition for

94. A full description of the requirements and PAPUC implementation of Act 129 through early 2010 is provided in a power point presentation of PUC Chairman James H. Cawley. James H. Cawley, Act 129 Update (Jan. 21, 2010), available at http://www.puc.state.pa.us/electric/pdf/PPT-Act129_Update012110-Cawley.pdf.

95. *Id.*

96. *Id.*

97. *Id.*

98. See, e.g., *Petition of PECO Energy Company for Approval of Its Smart Meter Technology Procurement and Installation Plan*, No. M-2009-2123944 (Pa. Pub. Util. Comm'n 2010); *Petition of PPL Energy Company for Approval of Its Smart Meter Technology Procurement and Installation Plan*, No. M-2009-2123945 (Pa. Pub. Util. Comm'n 2010) (advanced meters already deployed, approved plan is for pilot programs and expenditures to enhance system capability to meet all statutory/PUC requirements and to install any needed improvements); *Joint Petition of Metropolitan Edison Company, Pennsylvania Electric Company and Pennsylvania Power Company for Approval of Smart Meter Technology Procurement and Installation Plan*, No. M-2009-2123950 (Pa. Pub. Util. Comm'n 2010). The seventh utility, Allegheny Power Co., is being acquired by the First Energy Corp., and development and approval of its smart meter plan has been deferred until the acquisition is complete. All PAPUC documents are available at <http://www.puc.state.pa.us/>.

99. *Id.*

100. *Id.*

101. See, e.g., *Petition of PECO Energy Company for Approval of Its Energy Efficiency and Conservation Plan*, No. M-2009-2093215 (Pa. Pub. Util. Comm'n 2010); *Petition of PPL Electric Utilities Corporation for Approval of Its Energy Efficiency and Conservation Plan*, No. M-2009-2093216 (Pa. Pub. Util. Comm'n 2010); *Petition of West Penn Power Company for Approval of Its Energy Efficiency and Conservation Plan*, No. M-2009-209-3216 (Pa. Pub. Util. Comm'n 2010).

approval of a dynamic pricing pilot program, and in December the PAPUC approved a voluntary time-of-use rate program for PPL.¹⁰²

9. Texas

Customers of Oncor Electric Delivery Company, LLC (Oncor), filed a lawsuit against the utility in March 2010 claiming that Smart Meters installed by Oncor had resulted in customers being overcharged and alleging fraud and negligence on the part of Oncor in relation to Smart Meter deployment.¹⁰³ The suit was dismissed in August 2010.¹⁰⁴

II. DEMAND RESPONSE DEVELOPMENTS

A. *Federal and Regional Transmission Organization/Independent System Operator Developments*

1. Federal Energy Regulatory Commission

a. EnergyConnect, Inc. Order

On January 19, 2010, the FERC issued a precedent-setting order granting EnergyConnect, Inc. (ECI), an Aggregator of Retail Customers, market-based rate authority for the purpose of providing demand response services.¹⁰⁵ In addition to granting ECI market-based rate authority, the decision clarified the FERC's position that demand response activities are not subject to its jurisdiction.¹⁰⁶ Specifically, the FERC held that:

where an entity is only engaged in the provision of demand response services, and makes no sales of electric energy for resale, that entity would not own or operate facilities that are subject to the [FERC]'s jurisdiction and would not be a public utility that is required to have a rate on file with the [FERC].¹⁰⁷

In reaching this conclusion, the FERC stated that it would no longer rely on its previous characterization of demand response as a "sale for resale" and that it now views "'demand response' as 'a reduction in the consumption of electric energy by customers . . . in response to an increase in the price of electric energy or to incentive payments designed to induce lower consumption.'"¹⁰⁸ However, the FERC found that demand response providers may nevertheless become

102. *Petition of PECO Energy Company for Approval of Its Initial Dynamic Pricing and Customer Acceptance Plan*, No. M-2009-2123944 (Pa. Pub. Util. Comm'n Oct. 28, 2010), available at <http://www.puc.state.pa.us/pcdocs/1100283.pdf>; Press Release, Pa. Pub. Util. Comm'n, PUC Approves Updated Time-of-Use Rate for PPL Residential, Small Business Customers (Dec. 2, 2010), http://www.puc.state.pa.us/General/press_releases/Press_Releases.aspx?ShowPR=2670.

103. *Petition of Plaintiff, Cordts v. Oncor Electric Delivery Co.* (No. DC-10-03504) (Dallas Cnty., Tex. 162nd Judicial Dist. Ct. Mar. 26, 2010).

104. *Cordts v. Oncor Electric Delivery Co.*, No. DC-10-03504 (Dallas Cnty., Tex. 162nd Judicial Dist. Ct. Mar. 26, 2010).

105. *EnergyConnect, Inc.*, 130 F.E.R.C. ¶ 61,031 (2010).

106. *Id.* at P 32.

107. *Id.* at P 30.

108. *Id.* at P 31 (citing 18 C.F.R. § 35.28(b)(4) (2009)).

FERC-jurisdictional if they engage in transactions involving the sale or transmission of electric energy for resale.¹⁰⁹

b. National Action Plan on Demand Response

The above-referenced EISA directs the FERC to develop a National Action Plan that: 1) identifies the requirements for technical assistance to states to allow them to maximize the amount of demand response that can be developed and deployed; 2) designs and identifies requirements for implementation of a national communications program that includes broad-based customer education and support; and 3) develops or identifies analytical tools, information, model regulatory provisions, model contracts, and other support materials for use by customers, states, utilities, and demand response providers.¹¹⁰

In June 2010, the FERC released its National Action Plan on Demand Response in response to the mandates of the EISA.¹¹¹ The National Action Plan calls for the formation of a coalition to implement the National Action Plan that includes, and coordinates the efforts of, state and local governing officials, utilities and load-serving entities, demand response providers, regional transmission organizations and independent system operators (RTOs/ISOs), consumer advocates, commercial and industrial customers, the federal government, existing coalitions, and other stakeholders with respect to the strategies and activities described in the National Action Plan.¹¹²

The National Action Plan sets forth a number of strategies and activities that will be pursued to fulfill the objectives in EISA section 529.¹¹³ Steps to fulfill each of the three broad mandates of the EISA include:

1) for technical assistance to states, the establishment of a national forum on demand response, conducting informational and educational sessions for policymakers and regulators, formation of a panel of demand response experts, sponsorship of academic quality technical papers on demand response, creation of a program of technical assistance for demand response, and creation of demand response grants at the state level;¹¹⁴

2) for development of a national communications program, the creation of a program with attributes that include a communications umbrella to provide consistent messages regarding demand response, assistance for local implementation of demand response programs, and direct outreach;¹¹⁵ and

3) for development of analytical tools, information, model regulatory provisions, model contracts, and other support materials for use by customers, states, utilities, and demand response providers, the development of tools such as a web-based clearing house of demand response materials, including case studies of state laws, regulations, and tariffs, databases of pilot programs and markets;

109. *Id.* at P 29.

110. Energy Independence and Security Act of 2007, Pub. L. No. 110-140, § 529, 121 Stat. 1492, 1664 (to be codified at National Energy Conservation Policy Act, 42 U.S.C. §§ 8241, 8279).

111. FERC, NATIONAL ACTION PLAN ON DEMAND RESPONSE, Docket No. AD09-10 (June 17, 2010) (National Action Plan), *available at* <http://www.ferc.gov/legal/staff-reports/06-17-10-demand-response.pdf>.

112. *Id.* at ES-2.

113. *Id.*

114. *Id.* at 24-33.

115. *Id.* at 34-58.

quantitative and qualitative summaries; use of standard, comparable metrics; online message board capability; and information about the development of standards and protocols.¹¹⁶ This third component would also include development or enhancement of demand response estimation tools and methods.¹¹⁷

Section 529 of the EISA also calls for the FERC and the Secretary of Energy to develop a proposal to implement the National Action Plan and submit the proposal to Congress.¹¹⁸

c. Notice of Proposed Rulemaking and Supplemental Notice of Proposed Rulemaking for Compensation for Demand Response Resources

In March 2010, the FERC issued a Notice of Proposed Rulemaking (NOPR)¹¹⁹ proposing to establish regulations governing the compensation of demand response resources¹²⁰ that participate in organized energy markets such as ISOs/RTOs.

The FERC explained that participants in FERC-sponsored technical conferences stated that the continued small role of demand response providers in wholesale markets related to these providers deferring investment in demand response because they lacked confidence regarding the existence of stable competitive pricing structures necessary to sustain appropriate price signals.¹²¹ The Demand Response Compensation NOPR proposes to require each FERC-approved ISO and RTO that has a tariff provision providing for participation of demand response resources in its energy market to pay demand response resources, in all hours, the market price for energy, i.e., the full locational marginal price (LMP), for demand reductions made in response to price signals.¹²² The FERC clarified that the regulations would apply only for compensation for demand response providers participating as resources in organized wholesale energy markets, such as day-ahead and real-time energy markets, but would not apply to programs that ISOs and RTOs administer for reliability or emergency conditions.¹²³ The FERC also solicited comment on alternative approaches to compensating demand response resources participating in organized wholesale energy markets, and the merit of those approaches, in comparison to the one proposed in the NOPR.¹²⁴

116. *Id.* at 58-79.

117. *Id.*

118. *Id.*

119. Notice of Proposed Rulemaking, Demand Response Compensation in Organized Wholesale Energy Markets, 130 F.E.R.C. ¶ 61,213 (2010), 75 Fed. Reg. 15,362 (2010) (to be codified at 18 C.F.R. pt. 35) [hereinafter *NOPR*].

120. FERC regulations define demand response resources as “resource[s] capable of providing demand response.” 18 C.F.R. § 35.28 (b)(5) (2010). “Demand response means a reduction in the consumption of electric energy by customers from their expected consumption in response to an increase in the price of electric energy or to incentive payments designed to induce lower consumption of electric energy.” *Id.* § 35.28 (b)(4).

121. *NOPR*, *supra* note 119, at P 9.

122. *Id.* at P 11.

123. *Id.* at PP 1 n.4, 11.

124. *Id.* at P 20.

In August 2010, the FERC issued a Supplemental NOPR¹²⁵ seeking additional comments on whether the Commission should adopt requirements related to two demand response compensation issues: (1) if the FERC were to adopt a net benefits test for determining when to compensate demand response providers, what, if any, requirements should apply to the methods for determining net benefits; and (2) what, if any, requirements should apply to how the costs of demand response are allocated.¹²⁶ The FERC explained that the supplemental request for information was a response to comments by many commenters who oppose paying the LMP in all hours for demand response and, rather, suggest applying tests to measure the net benefits of such compensation to determine when the LMP should apply.¹²⁷ The FERC said that the request for comments regarding cost allocation was in response to comments that led the FERC to believe that issues concerning cost allocation may be integrally related to the proposal relating to demand response compensation and that therefore cost allocation issues merited further exploration.¹²⁸ In September 2010, the FERC held a technical conference on demand response compensation.¹²⁹

d. North America Power Partners

In October 2010, the FERC approved a settlement between the FERC's Office of Enforcement (OE) and North America Power Partners (NAPP) resulting from an OE investigation into NAPP's activities in PJM Interconnection, LLC's (PJM) demand response markets.¹³⁰ NAPP, which acts as a curtailment service provider assisting individual demand response resources to participate in demand response markets, agreed to pay a civil penalty of \$500,000, disgorge \$2,258,127, plus interest, in unjust profits, and to undertake compliance monitoring to settle the investigation.¹³¹ The FERC said that absent consideration of NAPP's financial viability and its ability to make payments under a settlement, the OE would have sought a significantly higher civil penalty and stated that it would likely seek a higher penalty for similar conduct by a more financially viable entity in the future.¹³²

The settlement, in which NAPP neither admits nor denies the OE's allegations, relates to NAPP's participation in several PJM demand response programs in 2007 and 2008.¹³³ "PJM's Synchronized Reserve Market is an hourly ancillary services market that complements PJM's Interchange Energy Market by allowing PJM to respond to sudden changes and serve load immediately in the event of a system contingency."¹³⁴ From 2007 to July 2008,

125. Supplemental Notice of Proposed Rulemaking and Notice of Technical Conference, Demand Response Compensation in Organized Wholesale Energy Markets, 132 F.E.R.C. ¶ 61,094 (2010), 75 Fed. Reg. 47,499 (2010) (to be codified at 18 C.F.R. pt. 35) [hereinafter *Supplemental NOPR*].

126. *Id.*

127. *Id.* at PP 6-7.

128. *Id.* at P 12.

129. FERC, Notice of Technical Conference, No. RM10-17-000 (Aug. 2, 2010), available at <http://www.ferc.gov/EventCalendar/Files/20100827164924-RM10-17-000SuppITC.pdf>.

130. *N. Am. Power Partners*, 133 F.E.R.C. ¶ 61,089 (2010).

131. *Id.* at P 1.

132. *Id.* at P 19.

133. *Id.* at PP 2, 3.

134. *Id.* at P 4.

the OE found that NAPP offered several resources into the market at times when the resources had reported to NAPP they were unavailable to respond to a Synchronized Reserve Event and also failed to notify NAPP's resources of nine synchronized reserve events to which the resources had a duty to respond, causing NAPP's resources to fail to respond.¹³⁵ These actions led the OE to conclude that NAPP had violated several PJM Open Access Transmission Tariff (OATT) provisions and that such conduct also constituted a fraudulent scheme or artifice committed with scienter in connection with a jurisdictional transaction in violation of 18 C.F.R. § 1c.2 (2010).¹³⁶

Other NAPP activities involved in the settlement included NAPP's participation in the PJM Interruptible Load for Reliability (ILR) capacity market.¹³⁷ The OE found that as part of the registration process for the 2007/2008 ILR planning season, NAPP submitted fifty-two inaccurate PLC values, which in the aggregate overstated the PLC values of NAPP's registered resources by 39.5 MW.¹³⁸ OE determined that NAPP's submission of inaccurate PLC data for the 2007/2008 ILR program violated a PJM OATT provision.¹³⁹

The OE also determined that NAPP registered 101 resources in the ILR program before obtaining their authorization or verification of their willingness and ability to participate in that year's program prior to the registration deadline.¹⁴⁰ The OE determined that the registration of 101 resources in the 2008/2009 ILR program without authorizations violated PJM's OATT and also constituted a fraudulent scheme or artifice committed with scienter in connection with a jurisdictional transaction in violation of 18 C.F.R. § 1c.2 (2010).¹⁴¹ The OE also found that NAPP engaged in two "minor" tariff violations related to its participation in PJM's energy market.¹⁴²

2. RTO/ISO Activity

Beginning in late 2009 but continuing through 2010, the FERC issued a series of Orders approving or requiring modification to the proposal submitted by RTO/ISOs with respect to compliance with Order No. 719, which was originally issued in 2008 and modified following rehearing in 2009 through Order No. 719-A.¹⁴³

In its April 2009 compliance filing to Order No. 719, the California ISO (CAISO) advised that demand response was permitted to participate in portions of its Ancillary Services Market (i.e., non-spinning reserves & imbalance

135. *Id.* at P 6.

136. *Id.* at P 7.

137. *Id.* at P 9.

138. *Id.* at P 10.

139. *Id.*

140. *Id.* at P 11.

141. *Id.* at P 12.

142. *Id.* at P 14.

143. Order No. 719, *Wholesale Competition in Regions with Organized Electric Markets*, F.E.R.C. STATS & REGS. ¶ 31,281 (2008), 73 Fed. Reg. 64,100 (2008) (to be codified at 18 C.F.R. pt. 35), *order on reh'g*, Order No. 719-A, F.E.R.C. STATS. & REGS. ¶ 31,292 (2009), 74 Fed. Reg. 37,776 (2009) (to be codified at 18 C.F.R. pt. 35).

energy), but not regulation or spinning reserve service.¹⁴⁴ This is because Western Electricity Coordinating Council standards referenced in its tariff require that only generation supply the regulation and spinning reserve service.¹⁴⁵ CAISO advised, however, that it would shortly file a tariff modification to eliminate this limitation and would also propose pilot projects to evaluate the feasibility of smaller demand response resources participating directly in its markets.¹⁴⁶ Further, CAISO advised that its current market design and software would not permit demand response resource aggregation, but that it would also shortly remove this limitation.¹⁴⁷ Finally, CAISO provided a Consultant's Report to comply with Order No. 719's requirement that it identify remaining barriers to demand response participation in its markets and propose solutions to such barriers.¹⁴⁸ The FERC approved this "roadmap" for future compliance with Order No. 719's requirements.¹⁴⁹ On September 10, 2010, the FERC approved a proposal from CAISO that expanded demand response's participation in its ancillary services market.¹⁵⁰ To achieve that result, CAISO (as did PJM in its filing) modified its existing market participation technical requirements to reduce the required minimum rated capacity for load to participate from one megawatt to 500 kilowatts and continuous operating capability from two hours to thirty minutes.¹⁵¹ In addition, CAISO revised the method used to measure continuous energy.¹⁵² The FERC approved the proposal as a significant forward step.¹⁵³ In a separate Order, the FERC approved CAISO's Proxy Demand Resource proposal, pursuant to which an Aggregator combines and bids demand response resources from smaller retail customers into CAISO's markets.¹⁵⁴ The FERC, however, rejected CAISO's proposed requirement that Aggregators be approved by the end-user's load serving entity prior to registration being permitted, and only partially approved CAISO's proposed mitigation and abuse monitoring provisions by rejecting a proposal to suspend Aggregator registration should demand response resources be called upon and not perform as expected.¹⁵⁵

On November 2, 2010, the CAISO Board of Governors approved a third demand response product, Reliability Demand Response, which, once approved by the FERC, is intended to provide the opportunity for traditional regulated demand response resources to participate in the CAISO markets.¹⁵⁶ CAISO, noting that demand response resources are compensated with the nodal prices at locations where demand reductions occur and not broader average prices, asserts

144. CAISO, 129 F.E.R.C. ¶ 61,157 (2009).

145. *Id.* at PP 17-18.

146. *Id.* at P 23.

147. *Id.* at P 18.

148. *Id.* at PP 24-34.

149. *Id.* at P 35.

150. CAISO, 132 F.E.R.C. ¶ 61,211 (2010).

151. *Id.* at P 3.

152. *Id.*

153. *Id.* at P 26.

154. CAISO, 132 F.E.R.C. ¶ 61,045 (2010).

155. CAISO, 132 F.E.R.C. ¶ 61,211 (2010); CAISO, 132 F.E.R.C. ¶ 61,045 (2010).

156. Press Release, CAISO, ISO Board Approves Reliability Demand Response Product (Nov. 2, 2010), available at <http://www.caiso.com/2842/2842b82c63430.pdf>.

that these actions will expand demand response participation in its markets as compared to traditional regulatory programs.¹⁵⁷

The Midwest ISO (MISO) filed an initial compliance filing in response to Order No. 719 on April 16, 2009.¹⁵⁸ In its filing, MISO explained that its ancillary service market (ASM – whose operation was initiated in January 2009) already permits demand response's participation on a basis comparable with supply resources.¹⁵⁹ MISO also responded to the Order's requirements for explanations respecting how baselines for demand response resources effect measurement and verification would be determined.¹⁶⁰ As its proposal for Aggregator participation in the ASM had not yet been fully vetted in its stakeholder processes, the latter was conceptually described in the compliance filing but not formally included.¹⁶¹ On October 2, 2009, MISO made a second filing seeking compliance with this requirement.¹⁶² FERC has not yet ruled on either compliance filing. On February 2, 2010, FERC approved a MISO-proposed expansion in DSM's participation in its ASM, i.e., to permit DDR-Type I resources (i.e., those with fixed capacity such as from load interruption) to provide spinning reserves as well as supplemental reserves as had previously been allowed.¹⁶³ The FERC also approved MISO's requirement that such resources have a minimum interruption duration of sixty minutes to qualify for this service, but rejected its proposed mitigation procedures applicable to these resources.¹⁶⁴ DDR-Type I resources are not permitted to set market clearing prices or to provide regulation service.¹⁶⁵ DDR-Type II resources, which had previously been permitted to provide each of ASM's three services and are permitted to set market clearing prices, are not based on load curtailment but rather behind the meter generation.¹⁶⁶

On January 21, 2010, the FERC approved, subject to further compliance filing, the compliance filing submitted by ISO New England Inc. (ISO-NE) and the New England Power Pool (NEPOOL) Participants Committee (together with ISO-NE, the Filing Parties) pursuant to Order No. 719.¹⁶⁷ With respect to the

157. *Id.*

158. *MISO*, 127 F.E.R.C. ¶ 61,054 (2009).

159. *Id.* at P 3.

160. The FERC had approved DSM participation in MISO's ASM in its approval of the creation of that market. *See MISO*, 122 F.E.R.C. ¶ 61,172 (2008).

161. *MISO*, 127 F.E.R.C. 61,054 at P 153 (2009).

162. Letter from Gregory A. Troxell, Assistant General Counsel, MISO, to Hon. Kimberly D. Bose, FERC Secretary, MISO Order No. 719 Compliance Filing, No. ER09-1049-000 (Apr. 28, 2009), *available at* http://www.midwestmarket.org/publish/Document/62c6cd_120e7409639_-7ef50a48324a/Entire%20Filing.pdf?action=download&_property=Attachment; Letter from Arthur W. Iler, Assistant General Counsel, MISO, to Hon. Kimberly D. Bose, FERC Secretary, MISO Filing re Aggregators of Retail Customers, No. ER09-1049-000 (Oct. 2, 2009), *available at* http://www.midwestmarket.org/publish/Document/6b6059_1239ec7b046_-768b0a48324a?rev=4; POTOMAC ECONOMICS, 2009 STATE OF THE MARKET REPORT – FOR THE MIDWEST ISO at 128-136 (June 2010), *available at* http://www.midwestmarket.org/publish/Document/55f670_12a43afcc88_-7f610a48324a/2009%20State%20of%20the%20Market%20Report.pdf?action=download&_property=Attachment.

163. *Midwest ISO*, 130 F.E.R.C. ¶ 61,087 (2010).

164. *Id.*

165. *Id.*

166. *Id.*

167. *ISO New England Inc. and New England Power Pool*, 130 F.E.R.C. ¶ 61,054 (2010).

issue of demand response resource comparability, the FERC determined that the Filing Parties did not sufficiently demonstrate compliance with market-clearing price requirements for demand resources in the ancillary services market, required that the ISO address certain compensation issues in the then-ongoing stakeholder process exploring the treatment of demand response resources in the energy markets, and required ISO-NE to demonstrate whether Dispatchable Asset Related Demand (DARD) meets with the comparability requirements of Order No. 719 as they pertain to ancillary services.¹⁶⁸

In a compliance filing submitted on April 21, 2010, the Filing Parties explained that the FERC's Demand Response Compensation NOPR had redirected the focus of the New England stakeholder process away from addressing demand response resource compensation issues as previously described to the FERC and toward compliance with the eventual outcome of the Demand Response Compensation NOPR proceeding.¹⁶⁹ With respect to the FERC's concerns regarding DARD, the Filing Parties provided further explanation of how the DARD program complies with Order No. 719's comparability requirement, and removed the five megawatt load size requirement and aggregation prohibition that had previously applied to DARD.¹⁷⁰ The FERC accepted the Filing Parties' compliance filing, effective on or after December 1, 2010, by letter order dated July 23, 2010.¹⁷¹

The New York ISO (NYISO) submitted its Order No. 719 compliance filing on May 15, 2009, amended June 17, 2009, in which it explained that the NYISO's tariffs already complied with Order No. 719's directives regarding demand response comparability.¹⁷² In an order issued in November 2009, the FERC instructed the NYISO to (1) demonstrate the reasonableness of its proposal to require demand response resources to use the same telemetry and communications equipment used by generators; and (2) provide an action plan identifying changes necessary to allow demand response to participate in the real-time energy market to provide energy imbalance service.¹⁷³ In a compliance filing submitted February 25, 2010, the NYISO explained that, with respect to its telemetry and communications requirements, it "is not aware of any other practicable alternative that would satisfy the requirements of its market design and reliability rules," although it remained "open to exploring alternative technical requirements that could be adopted in the future."¹⁷⁴ In addition, the NYISO proposed a plan of action to allow demand response resources to

168. *Id.*

169. Compliance Filing, *Filing of ISO New England Inc. and New England Power Pool Filing in Response to Commission Order on ISO New England Inc.'s Order No. 719 Compliance Filing*; Docket No. ER 09-1051-003, ISP New England, Inc., and New England Power Pool (Apr. 21, 2010), available at http://www.iso-ne.com/regulatory/ferc/filings/2010/apr/er09-1051-003_4-21-10_90-day_order719_compliance-standards.pdf.

170. *Id.*

171. Letter from Jignasa Gadani, FERC Director of Electric Power, to James H. Douglass and Michelle C. Gardner (July 23, 2010), available at <http://elibrary.ferc.gov/idmws/nvcommon/NVViewer.asp?Doc=12397678:0>.

172. *N.Y. Indep. Sys. Operator, Inc.*, 133 F.E.R.C. ¶ 61,072 (2010).

173. *N.Y. Indep. Sys. Operator, Inc.*, 129 F.E.R.C. ¶ 61,164 (2009).

174. Letter from Ted J. Murphy, Attorney, to Hon. Kimberly Bose, FERC Secretary, at p. 3 (Feb. 25, 2010), available at <http://elibrary.ferc.gov/idmws/nvcommon/NVViewer.asp?Doc=12283470:0>.

participate in the real-time energy market to provide energy imbalance service, a process the NYISO anticipates will not take place before the middle of 2012.¹⁷⁵ The FERC accepted this compliance filing by order issued April 23, 2010.¹⁷⁶

In December 2009, the FERC approved the proposal of PJM to integrate demand resources into PJM's ancillary services markets, but required the filing of additional supporting analyses to demonstrate the procedures that would be used to assure that compensated load reductions would indeed be real and result from market participation. These procedures, including the development of a baseline usage level from which demand response would be measured and consultation procedures with the demand response provider, were approved in an August 2010 Order.¹⁷⁷ PJM had advised in its Order No. 719 compliance filing that it already complied with Order No. 719's requirements relative to demand response participation in its ancillary service markets.¹⁷⁸ PJM noted that differences exist in other technical requirements applicable to demand response as compared to generation participating in its ancillary service markets and explained the reasons for these differences as being attributable to differences in the characteristics of demand response resources versus generation.¹⁷⁹ The FERC generally permitted these differences, noting that comparability does not require identical rules and technical standards applicable to both generation and demand response resources given PJM's explanation of differences in their character.¹⁸⁰

The FERC also reviewed PJM and Monitoring Analytics' (PJM's Market Monitor) required reports assessing and suggesting solutions for remaining barriers to comparable treatment of demand response in PJM markets, and the comments of demand response providers made upon those reports.¹⁸¹ PJM and Monitoring Analytics identified contentious processes for establishing customer usage baselines and demand response effect verification processes (including a lack of assurance that measured demand response is in fact attributable to market price incentives and not demand response provider operating or commercial pressures) as remaining barriers, along with the lack of time varying retail rates and infrastructure to permit such rates (i.e. implementation of price responsive demand) as such barriers.¹⁸² Demand response providers, in addition to the above, identified various credit and collateral requirements in PJM's capacity

175. *Id.*

176. *N.Y. Indep. Sys. Operator, Inc.*, 131 F.E.R.C. ¶ 61,064 (2010).

177. *PJM*, 132 F.E.R.C. ¶ 61,123 (2010); *PJM*, 129 F.E.R.C. ¶ 61,250 (2009). FERC also approved implementation of a pilot program whose development it had required in Order No. 719 to examine the feasibility of smaller DR providing ancillary services in its late 2009 Order. Similar such pilot programs have been approved for other RTO/ISOs in the Orders cited below. In *PJM*, 123 F.E.R.C. ¶ 61,257 (2008), in response to concerns expressed by PJM and its MMU that certain DR payments were being made to entities not actually reducing their usage in response to their DR program participation (but rather due to independent operational and commercial forces), FERC approved revised procedures proposed by PJM to compute "customer baseline load" for purposes of measuring DR program reductions and expanded verification processes. These were then incorporated into PJM's Order No. 719 compliance filings.

178. *PJM*, 129 F.E.R.C. ¶ 61,250 at PP 8-19 (2009).

179. *Id.*

180. *Id.*

181. *Id.* at P 105.

182. *Id.* at P 28.

market and reliance upon distribution companies and load serving entities (i.e., viewed as competitors of and antagonistic to demand response providers) for data used in the baseline establishment and effect verification process.¹⁸³ The FERC noted that most of these barriers remained subject to PJM stakeholder and other efforts to achieve their improvement, and urged that these efforts continue.¹⁸⁴ Finally, the FERC, in Order No. 719A, had expanded its acceptance that State Regulators or laws could prohibit end-user demand response resources from participating in PJM's markets.¹⁸⁵ The FERC reviewed and approved PJM tariff language implementing this determination in a series of Orders issued in 2009-10.

On December 2, 2010, PJM filed under Federal Power Act section 205 to amend its OATT to establish two additional product alternatives for demand resources.¹⁸⁶ PJM explained that its existing emergency demand response product, compensated through its reliability pricing model capacity market, permits interruption of participating resources only ten times and for only six hours per interruption.¹⁸⁷ However, recent studies of PJM load and available capacity resources indicate that there is a growing risk that such demand resources will need to be interrupted more than ten times per year, and for longer periods than six hours, if reliability is to be maintained.¹⁸⁸ As explained in the Cover Letter to its filing:

PJM has experienced tremendous growth in the level of demand resources committed to PJM as capacity resources through its annual forward capacity auctions under the Reliability Pricing Model ("RPM"). However, demand resources currently have only a single product definition – established nearly twenty years ago and carrying significant summer peak period limitations on resource availability – by which they can commit their resources to PJM. Given the increase in the PJM region's dependence on demand resources to maintain reliability during periods when system supply resources are short, the current product definition is no longer adequate to endure that reliability requirements are met. Accordingly, PJM proposes to establish two additional demand resource products, one available throughout the year, and one with an expanded summer commitment period compared to the current product.¹⁸⁹

Accordingly, while continuing to offer its existing product as "Limited Demand Resource," PJM has requested approval to add "Annual Demand Resource" and "Extended Summer Demand Resource" (ESDR) products to its market structure.¹⁹⁰ Each of these products will permit PJM to interrupt the resource for an unlimited number of times, and for a 10 hour period during the hours of 10:00 AM to 10:00 PM daily, though the ESDR is available only during the months of May to September.¹⁹¹ The new products will also permit demand

183. *Id.* at P 80.

184. *Id.* at PP 25-34.

185. *See generally, PJM*, 128 F.E.R.C. ¶ 61,238 (2009), *order on reh'g*, 131 F.E.R.C. ¶ 61,069 (2010).

186. Letter from Paul M. Flynn, Barry S. Spector, Jeanine Schleiden & Craig Glazer, PJM, to Hon. Kimberly D. Bose, FERC Secretary (Dec. 2, 2010), *available at* <http://www.pjm.org/~media/documents/ferc/2010-filings/20101202-er11-2288-000.ashx>.

187. *Id.*

188. *Id.*

189. *Id.*

190. *Id.* at 20-21.

191. *Id.* at 22.

response resources to increase its participation as a percentage of total resources in the PJM capacity market as recent increases (i.e., to approximately 6%) have in substantial part been the cause of the increased risk to reliability necessitating development of these new products.¹⁹² PJM further explains that it will seek defined amounts of each product in its May 2011 RPM auction and does not expect that pricing for the different products will be significantly different.¹⁹³ A number of Protests and Comments have been filed to the proposal, which request that the FERC act by early February 2011.¹⁹⁴

The Southwest Power Pool (SPP) has but one competitive market, its real-time Energy Imbalance Service Market.¹⁹⁵ Prior to its Order No. 719 compliance filing, SPP had revised its tariff to permit demand response resources to participate in that market.¹⁹⁶ It then proposed in its compliance filing further tariff language to promise generally that demand response resources would receive comparable treatment to supply resources, but the FERC found the two proposals insufficient as SPP applied without explanation or demonstration of actual comparability, the same technical requirements (i.e., bidding parameters for duration, frequency and amount of service and applicable telemetry, metering and other equipment requirements) as applied to supply resources.¹⁹⁷ The FERC noted that, to achieve comparability, these technical requirements may in fact need to be different and tailored to the character of demand response resources.¹⁹⁸ The FERC also rejected SPP's proposed approach to define the baseline usage to measure and verify actual demand response reductions entitled to compensation, which approach merely provided that the matter would be agreed to with the demand response provider in the future.¹⁹⁹ These same inadequacies, the FERC found, applied to SPP's proposal to permit Aggregator participation in its market, and thus it too was found insufficient.²⁰⁰ Finally, noting that SPP's demand response program is in its "nascent stages," the FERC granted SPP an additional six months to file its demand response assessment report.²⁰¹ SPP filed a modified program in May 2010 which seeks to correct these matters, but the modified compliance filing has not yet been the subject of a FERC ruling.²⁰²

3. EPA "RICE" Rules

In March 2010 and August 2010, the Environmental Protection Agency (EPA) issued final rules providing national emission standards for hazardous air

192. *Id.* at 6.

193. *Id.* at 1.

194. *See generally id.*

195. Letter from Wendy N. Reed and Matthew K. Segers, Attorneys for SPP, to Hon. Kimberly D. Bose, FERC Secretary (Feb. 24, 2009), *available at* <http://elibrary.ferc.gov/idmws/nvcommon/NVViewer.asp?Doc=11950230:0>.

196. *Id.*

197. *Id.*

198. *Id.*

199. *Id.*

200. *Sw. Power Pool, Inc.*, 129 F.E.R.C. ¶ 61,163 at P 16 (2009).

201. *Id.*

202. Letter from Wendy N. Reed & Matthew K. Segers to Hon. Kimberly D. Bose, FERC Secretary (May 19, 2010), *available at* <http://elibrary.ferc.gov/idmws/nvcommon/NVViewer.asp?Doc=12349562:0>.

pollutants for existing stationary compression ignition (CI) reciprocating internal combustion engines (RICE) and spark ignition (SI) RICE, respectively (RICE Rules).²⁰³ The RICE Rules address emissions from RICE less than or equal to 500 horsepower located at major sources and all existing stationary RICE located at area sources.²⁰⁴ Existing rules addressed emissions from RICE greater than 500 horsepower located at major sources. Because these types of engines are often used to generate back-up electricity, these rules have the potential to affect participants in demand response programs.

The CI RICE rule established standards limiting emissions of air toxins from existing stationary diesel engines located at major and area sources.²⁰⁵ The EPA received two petitions for reconsideration: one from the Delaware Department of Natural Resources and Environmental Control, arguing that allowing fifteen hours of emergency demand response operation for emergency emissions would undercut the progress Delaware has made in reducing hazardous air pollutants; and one from Enernoc, asserting that the EPA should revise the rule to allow emergency demand response resource engines to be operated for a maximum of sixty hours per year or the minimum hours required by the ISO/RTO tariff, whichever is less.²⁰⁶ In December 2010, the EPA responded by issuing a notice announcing reconsideration of and requesting public comment regarding the allowance and corresponding duration of emergency engine operation in emergency demand response programs.²⁰⁷ This public comment will expire sixty days following publication in the Federal Register.

The SI rule covers existing SI engines at major sources and all existing SI engines at area sources, requiring catalysts, maintenance practices, and Continuous Parameter Monitoring Systems (CPMS), depending on engine power level.²⁰⁸ The week of October 18, 2010, the Natural Gas Industry, engine manufacturers, and other industry groups challenged the SI rule by filing petitions for reconsideration at the EPA, and by filing lawsuits at the D.C. Circuit.²⁰⁹ These parties claim that the CPMS requirement imposed on engines at smaller sources is infeasible, and additionally, restrictions placed on small emergency generating units for peak shaving programs and demand response

203. Final Rulemaking, National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, 75 Fed. Reg. 9,648 (2010) (to be codified at 40 C.F.R. pt. 63); Final Rulemaking; Correction, National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, 75 Fed. Reg. 37,732 (2010) (to be codified at 40 C.F.R. pt. 63); Final Rulemaking, National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, 75 Fed. Reg. 51,570 (2010) (to be codified at 40 C.F.R. pt. 63).

204. 75 Fed. Reg. 51,570 at 51,570.

205. 75 Fed. Reg. 9,648 at 9,648.

206. Notice of Reconsideration of Final Rule; Request for Public Comment; Notice of Public Meeting, National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, 75 Fed. Reg. 75,937 (2010) (to be codified at 40 C.F.R. pt. 63).

207. *Id.*

208. 75 Fed. Reg. 37,732 at 37,732.

209. See, e.g., INGAA, *Petition for Reconsideration, National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; Final Rule*, 75 Fed. Reg. 51570 (August 20, 2010), No. EPA-HQ-OAR-2008-0708, Oct. 19, 2010, available at <http://www.ingaa.org/File.aspx?id=10951>.

service should be lessened.²¹⁰ Court briefing will likely not be scheduled until the EPA rules on the pending petitions for reconsideration.

B. State Developments

Although to date most regulation of non-utility demand response providers has taken place at the federal and ISO/RTO level, in August 2010 the Maryland PSC initiated a proceeding that could impose new regulatory requirements on certain demand response providers in Maryland at the state level.²¹¹ The proceeding, which is awaiting a final order, centers on whether demand response providers are required to obtain licenses to operate in Maryland as electricity suppliers.²¹²

III. ENERGY EFFICIENCY DEVELOPMENTS

A. Federal Developments

1. Department of Energy Appliance Standards

Since January 2009, the DOE has issued or codified new efficiency standards for more than twenty different products. In 2010, the DOE issued a final rule amending the energy conservation standards for residential water heaters, direct heating equipment, and pool heaters.²¹³ The standards established in the final rule will be applied starting April 16, 2015, for residential water heaters, and April 16, 2013, for residential direct heating equipment and pool heaters.²¹⁴

2. DOE Enforcement Initiative

Beginning in the fall of 2009, the DOE established a new program within the Office of the General Counsel to systematically enforce federal energy and water efficiency standards that have been in existence for decades.²¹⁵ The DOE has also ramped up testing of ENERGY STAR appliances to verify products' energy efficiency claims.²¹⁶ The DOE's newly created Office of Enforcement has been proactive, issuing enforcement guidance, proposing regulatory revisions to improve the effectiveness of the DOE's enforcement efforts, and bringing numerous enforcement actions against companies for failing to comply with the DOE's rules and efficiency standards.²¹⁷ To date, the DOE has

210. *Id.*

211. Order No. 83545, *In the Matter of an Investigation of the Regulation of Curtailment Service Providers*, No. 9241 (Md. Pub. Serv. Comm'n Aug. 23, 2010) http://webapp.psc.state.md.us/Intranet/Casenum/CaseAction_new.cfm?RequestTimeout=500?

212. *Id.*

213. Final Rulemaking, Energy Conservation Standards for Residential Water Heaters, Direct Heating Equipment, and Pool Heaters, 75 Fed. Reg. 20,112 (2010) (to be codified at 10 C.F.R. pt. 430).

214. *Id.*; Correction, Energy Conservation Program: Energy Conservation Standards for Residential Water Heaters, Direct Heating Equipment, and Pool Heaters, 75 Fed. Reg. 21,981 (2010) (to be codified at 10 C.F.R. pt. 430).

215. *Recent Enforcement News*, ENERGY.GOV, http://www.gc.energy.gov/enforcement_news.htm (last visited Feb. 11, 2011).

216. *Id.*

217. *Id.*

collected nearly \$500,000 in civil penalties and removed over sixty-five products from the market that did not meet DOE's efficiency requirements.²¹⁸

B. State Developments

1. Appliance Standards

Although efficiency standards for many appliances are addressed at the federal level, states with standards that pre-date enactment of federal standards are generally permitted to enforce such standards until the corresponding federal standards become effective. Some states also have implemented efficiency standards for appliances not yet regulated by the DOE.

In September 2010, the California Office of Administrative Law approved amendments to the state's appliance efficiency regulations to include energy efficiency requirements for televisions, making California the first state to implement such measures.²¹⁹ The amendments, which were passed by the California Energy Commission in November 2009, apply to televisions with a screen size of fifty-eight inches or smaller sold in the state beginning January 2011.²²⁰

Under legislation passed in 2007, residential pool pumps sold for use in Connecticut after January 2010 are required to meet California energy efficiency standards, which require residential pool pumps to be either two-, multi- or variable speed.²²¹ In 2009, Arizona passed efficiency standards for residential pool pump and portable electric spas, which are also based on the California standards.²²² These standards will be effective for new and replacement installations beginning January 1, 2012.²²³

The District of Columbia passed legislation in 2007 creating new energy efficiency standards for six types of appliances.²²⁴ Four of those standards were preempted by Federal law.²²⁵ The remaining two apply to bottle-type water dispensers and commercial hot food holding cabinets sold in the District of Columbia on or after January 1, 2009, and installed on or after January 1, 2010.²²⁶ The statute also provides that the Mayor may adopt rules to either increase efficiency standards for the listed products or establish efficiency standards for products not listed if necessary to further promote energy conservation in D.C.²²⁷

218. *Id.*

219. 2009 Appliance Efficiency Rulemaking, Phase I, Part C, Docket No. 09-AAER-1C (Cal. Energy Comm'n July 14, 2010), available at <http://www.energy.ca.gov/2009publications/CEC-400-2009-023/CEC-400-2009-023-CMF.PDF>.

220. *Id.*

221. See generally Energy Efficiency Standards for Products, CONN. GEN. STAT. § 16a-48 (2010).

222. H.R. 2332, 49th Leg., 1st Sess. (Ariz. 2009).

223. *Id.*

224. Energy Efficiency Standards, D.C. CODE § 8-1771.01-.04 (2010).

225. *Id.*

226. *Id.*

227. *Id.*

Under Rhode Island's Energy and Consumer Savings Act of 2005²²⁸ and regulations promulgated by the Rhode Island Public Utilities Commission thereunder in 2007,²²⁹ every automatic commercial icemaker, commercial refrigerator, refrigerator-freezer, freezer, and large packaged air conditioning equipment manufactured on or after January 1, 2010, must meet certain minimum efficiency standards.²³⁰

Legislation passed by Washington state lawmakers in 2009, effective January 1, 2010, mandates energy efficiency standards for wine chillers designed and sold for use by an individual, hot water dispensers and mini-tank electric water heaters, bottle-type water dispensers, pool heaters, residential pool pumps, portable electric spas, and commercial hot food holding cabinets.²³¹

2. Other State Efficiency Developments

The IEE has reported that ratepayer funded electric efficiency budgets in the United States totaled over \$5.4 billion in 2010, having grown at an average annual rate of approximately 25% over the past three years.²³² The 2009 annual savings are stated to be over 92 terra-watt hours, which avoids emission of over 66 million metric tons of carbon dioxide at an average cost of 4.056 cents per kilowatt-hour, less than the cost of supplying the average consumed kilowatt-hour.²³³ The second paper notes that, as of April 2010, thirteen states have adopted and six are considering adoption of revenue decoupling, and seven have adopted a lost revenue recovery mechanism in connection with energy efficiency caused utility revenue reductions.²³⁴ Fourteen states have adopted flexible tariff rider or surcharge mechanism to facilitate recovery of the costs of utility implemented energy efficiency programs, and twenty have adopted performance incentives encouraging successful implementation of such programs.²³⁵

In July 2010, the Virginia State Corporation Commission (VSCC) adopted the Virginia Energy Sense program as an accessible and informative source for energy conservation and efficiency information.²³⁶ The program furthers a

228. Energy and Consumer Savings Act of 2005 Efficiency Standards, R.I. GEN. LAWS. § 39-27-5 (2010).

229. Rules and Regulations Establishing Minimum Efficiency Standards for Certain New Products Sold in the State of Rhode Island, R.I. Pub. Utils. Comm'n (2007), available at <http://sos.ri.gov/documents/archives/regdocs/released/pdf/PUC/4626.pdf>; 90-060 R.I. CODE R. § 016 (LexisNexis 2011).

230. Rules and Regulations Establishing Minimum Efficiency Standards for Certain New Products Sold in the State of Rhode Island, R.I. Pub. Utils. Comm'n (2007), available at <http://sos.ri.gov/documents/archives/regdocs/released/pdf/PUC/4626.pdf>; 90-060 R.I. CODE R. § 016 (LexisNexis 2011).

231. H.R. 1004, 61st Leg., Reg. Sess. (Wash. 2009).

232. IEE, SUMMARY OF RATEPAYER-FUNDED ELECTRIC EFFICIENCY IMPACTS, EXPENDITURES AND BUDGETS 1-3 (Jan. 2011), available at http://www.edisonfoundation.net/iee/issueBriefs/IEE_CEE2010_FINAL_ARupdate.pdf.

233. *Id.*

234. IEE, CHANGES IN STATE REGULATORY FRAMEWORKS FOR UTILITY ADMINISTERED ENERGY EFFICIENCY PROGRAMS 1-3 (Apr. 2010), available at http://www.edisonfoundation.net/iee/issueBriefs/IEE_RegulatoryChanges2007-2010.pdf.

235. *Id.*

236. Virginia Introduces Program to Encourage Statewide Energy Reduction, VSCC (July 28, 2010), http://www.scc.virginia.gov/newsrel/ves_launch_10.aspx.

statewide goal adopted by the Virginia General assembly of reducing Virginia electricity demand by 10% from 2006 levels by 2022.²³⁷ At the core of the Virginia Energy sense program is a comprehensive, interactive website, which provides consumers with helpful step-by-step videos, energy conservation tips, and an innovative tool to automatically track energy consumption.²³⁸ The VSCC also approved five new energy efficiency programs for Dominion Virginia Power during the year including air conditioner recycling, an efficient commercial HVAC replacement program, a low income audit program, and residential efficient lighting programs.²³⁹

237. *Id.*

238. VIRGINIA ENERGY SENSE, <http://www.virginiaenergysense.org> (last visited Feb. 1, 2009).

239. *SCC Approves Five Demand-Side Management Programs for Dominion Power Customers*, VSCC (Mar. 24, 2010), http://www.scc.virginia.gov/newsrel/e_domdsm_10.aspx.

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