ENERGY AND NATURAL RESOURCES MARKET REGULATION
2011 Annual Report[1]

I. ELECTRICITY MARKETS

A. Federal Developments

1. FERC Order No. 1000 Transmission Planning and Cost Allocation Reforms

On July 15, 2011, the Federal Energy Regulatory Commission (FERC) issued Order No. 1000.[2] The Final Rule addresses deficiencies in Order No. 890,[3] as identified by FERC. Order No. 890 required each public utility transmission provider to develop an open-access transmission tariff (OATT) and transmission planning process that satisfied nine principles: "(1) coordination, (2) openness, (3) transparency, (4) information exchange, (5) comparability, (6) dispute resolution, (7) regional participation, (8) economic planning studies, and (9) cost allocation for new projects."[4] Citing changes in the electricity industry, including the projected need for additional transmission resources to integrate new variable and renewable generation, and using information gathered from FERC technical conferences, FERC determined that reforms to the *pro forma* OATT were needed.[5]

FERC's objectives in issuing the Final Rule were to ensure (1) that transmission planning processes consider and evaluate regional transmission alternatives that may meet regional needs more effectively and cost-efficiently than alternatives identified in a local process and (2) that the costs of new transmission facilities selected in regional transmission plans are allocated fairly to those who benefit from those new facilities.[6] To accomplish these objectives, the Final Rule requires reforms including the use of a regional transmission planning process, the elimination of the federal right of first refusal for incumbent public utility transmission providers, interregional transmission coordination, and regional and interregional cost allocation.[7]

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[1]This report was prepared by the Energy and Natural Resources Market Regulation Committee Year-in-Review Vice-Chair Grace S. Kurdian, Watson, Farley & Williams, LLP, with the assistance of co-editor and Chair of the Energy and Natural Resources Market Regulation Committee Jeffrey M. Gray, Gray PLLC. Special thanks to the following authors for their contributions: Natara Feller, Law Offices of Natara Feller; Arshia Javaherian, Alliant Energy; Emily Pitlick, Van Ness Feldman; Brandon N. Robinson, Balch & Bingham LLP; F. Jack Stoddard, Manatt, Phelps & Phillips, LLP; and Jeremy D. Weinstein, Law Offices of Jeremy D. Weinstein, Esq.

[2]Final Rule, *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 136 FERC ¶ 61,051, Docket No. RM10-23-000; Order No. 1000 (July 21, 2011) (to be codified at 18 C.F.R. pt. 35) [hereinafter Final Rule], *available at* http://www.ferc.gov/whats-new/comm-meet/2011/072111/E-6.pdf.

[3]*Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241, *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228 (2009), *order on reh'g*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

[4]Final Rule, *supra* note 2, at P 18.

[5]*Id.* at P 30.

[6]*Id.* at P 4.

[7]*Id.* at P 68, 225, 345, 482.

First, under the Final Rule, each public utility transmission provider must participate in a regional transmission planning process that considers and evaluates transmission alternatives at the regional level, and that produces a regional plan.[8] The regional planning process must include public policy considerations, including local renewable portfolio standard (RPS) requirements, in determining transmission needs.[9] Public utility transmission providers are required to amend their OATTs to include procedures used in planning processes that allow for the evaluation of transmission needs based on local and regional public policy considerations.[10] Merchant transmission developers are required to provide information into the regional transmission planning process; but are not required to participate in regional transmission planning, because merchant transmission developers assume financial risk for their projects.[11] Proposed merchant transmission projects are considered and evaluated in the regional transmission planning process so that the process is "open," as required by the principles previously established in Order No. 890, and to prevent undue discrimination against non-incumbent transmission developers.[12] The Final Rule requires that each public utility transmission provider amend its OATT to describe a transparent and non-discriminatory process for evaluating whether to select a proposed transmission facility in a regional transmission plan for purposes of cost allocation.[13]

Second, the Final Rule eliminates the federal right of first refusal by incumbent public utility transmission providers for transmission facilities selected in a regional transmission plan.[14] This reform removes a perceived barrier to entry for merchant transmission developers that may otherwise discourage those developers from proposing alternative transmission solutions at the regional level.[15] Eliminating the right of first refusal is intended to encourage participation and investment by merchant transmission developers, potentially lowering costs to customers.[16] FERC has left to the transmission planning regions the task of developing qualification criteria for cost allocation that will apply equally to transmission projects proposed by incumbent and non-incumbent transmission developers.[17]

Third, the Final Rule reforms interregional transmission coordination to promote "clear and transparent procedures" for sharing information across the seams of neighboring transmission regions, to enable the identification of proposed facilities that more cost-effectively could meet the needs identified in regional transmission plans.[18] FERC declined to specify how neighboring transmission regions should share information, leaving implementation of those interregional coordination procedures to the regions.[19]

Fourth, the Final Rule provides for cost allocation reforms. FERC recognized that without minimum stated requirements for cost allocation methods, the methods used by public utility transmission providers might fail to adequately consider the benefits and beneficiaries of new transmission facilities, resulting in unjust or unreasonable rates or

[8]*Id*. at P 148.
[9]*Id*. at P 81, 203.
[10]*Id*. at P 207.
[11]*Id*. at PP 163-165. Costs for merchant transmission projects are recovered through negotiated rates rather than cost-based rates. *Id.* at P 119.
[12]*Id*. at PP 228-230.
[13]*Id.* at P 164.
[14]*Id*. at P 225.
[15]*Id*. at P 207.
[16]*Id*. at P 285.
[17]*Id*. at P 324.
[18]*Id*. at P 368, 396.
[19]*Id*. at P 397.

rates that are unduly discriminatory.[20] Public utility transmission providers must have, both within their own transmission planning regions and across neighboring planning regions, a common method or methods for allocating the costs of new transmission facilities selected in regional transmission plans.[21] The Final Rule does not require a single nationwide approach for interregional cost allocation, and allows neighboring regions the flexibility to develop appropriate methods.[22] While the Final Rule provides flexibility in determining cost allocation methods for regional and interregional transmission planning, it establishes six cost allocation principles to ensure that regional and interregional cost allocation methods are just and reasonable.[23] In the event of a failure to reach agreement on cost allocation methods, FERC will use the record in the relevant compliance filings to develop regional and interregional cost allocation methods that meet the six principles.[24]

Principle one requires that costs be allocated to those who will benefit in proportions that are roughly commensurate with the estimated benefits.[25] However, FERC declined to prescribe particular benefits or to further define "beneficiaries."[26] Principle two requires that there be no involuntary allocation of costs to non-beneficiaries.[27] FERC concluded that this principle is "essential" because it "expresses a central tenet of cost causation."[28] Principle three requires that if a benefit-to-cost ratio is used as a threshold to determine whether a transmission facility offers sufficient benefits to be selected in a regional transmission plan for cost allocation, or to qualify for interregional cost allocation, the ratio must not be so large as to exclude from cost allocation a "facilit[y] with significant positive net benefits."[29] Principle four requires that cost allocations be made solely within the relevant transmission planning regions, unless participants or beneficiaries outside those regions voluntarily agree to assume a portion of the costs.[30] Principle five requires that transparent methods be used to determine benefits, and to identify beneficiaries.[31] FERC concluded that requiring those methods to be open and transparent would ensure that the "methods are just and reasonable, and not unduly discriminatory or preferential."[32] Finally, principle six provides that a public utility transmission provider "may choose to use . . . different cost allocation method[s] for different types of transmission facilities," such as those required for reliability, congestion relief, or to achieve public policy goals.[33] Those cost allocation methods must be clearly and thoroughly explained in the compliance filing of the public utility transmission provider.[34]

Within twelve months of the Final Rule's effective date, each public utility transmission provider must submit compliance filings that revise the transmission provider's OATT or other filed documents, as necessary to meet the requirements of the

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[20] *Id*. at P 495.
[21] *Id*. at P 578.
[22] *Id*. at P 580.
[23] *Id*. at PP 603-604.
[24] *Id*. at P 607.
[25] *Id*. at P 622.
[26] *Id*. at PP 624-625, 628.
[27] *Id*. at P 637.
[28] *Id*. at P 637.
[29] *Id*. at P 646.
[30] *Id*. at P 657.
[31] *Id.* at P 668.
[32] *Id.* at P 669.
[33] *Id*. at P 685.
[34] *Id*.

Final Rule.[35] Furthermore, within eighteen months of the Final Rule's effective date, each public utility transmission provider must submit a compliance filing regarding interregional transmission coordination procedures and cost allocation methods.[36]

2. Environmental Regulations and Impact on Reliability

In 2011, much discussion in the electric utility industry centered around proposed environmental "regulations under development at the Environmental Protection Agency (EPA) that would impose new requirements on coal-fired power plants."[37] These include six Clean Air Act rules, two Clean Water Act rules, and a Resource Conservation and Recovery Act rule.[38] As a result of the rules, a number of coal-fired generating plants in the U.S. will need to be retired, replaced with other fuel sources such as natural gas, or retrofitted with environmental controls such as scrubbers, bag-houses, and other technologies. With all of these rules scheduled to be promulgated at approximately the same time, the rules have been characterized by some critics as (1) imposing significant costs and (2) "threatening the adequacy of electricity capacity," and thus the reliability of the electric grid, across the country.[39]

Various groups have studied the impact of the proposed regulations on electric-grid reliability.[40] Some studies indicate that compliance with these new regulations is

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[35]*Id*. at P 792.
[36]*Id*.
[37]JAMES E. MCCARTHY & CLAUDIA COPELAND, U.S. CONG. RESEARCH SERV., No. 7-5700, EPA'S REGULATION OF COAL-FIRED POWER: IS A "TRAIN WRECK" COMING? (August 8, 2011), *available at* http://www.lawandenvironment.com/uploads/file/CRS-EPA.pdf.
[38]*Id*. The rules generally considered in this context include (1) the Cross State Air Pollution Rule, (2) the Mercury and Air Toxics Standards Rule, (3) the New Source Performance Standards for Greenhouse Gas Emissions, (4) the Revised National Ambient Air Quality Standards, (5) the Revised Cooling Water Intake Rule, (6) the Revised Steam Electric Effluent Guidelines, and (7) rules for Coal Combustion Waste. *See id.* at 9-27.
[39]*Id.* at Summary.
[40]*See, e.g., Id.;* NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION (NERC), 2011 LONG TERM RELIABILITY ASSESSMENT (Nov. 2011), *available at* http://www.nerc.com/files/2011%20LTRA_Final.pdf; NERC, 2010 SPECIAL RELIABILITY SCENARIO ASSESSMENT (Oct. 2010), *available at* http://www.nerc.com/files/EPA_Scenario_Final.pdf; U.S. DEPARTMENT OF ENERGY (DOE), RESOURCE ADEQUACY IMPLICATIONS OF FORTHCOMING EPA AIR QUALITY REGULATIONS (Dec. 2011), *available at* http://energy.gov/sites/prod/files/2011%20Air%20Quality%20Regulations%20Report_120111.pdf; JENNIFER MACEDONIA ET AL., BIPARTISAN POLICY CENTER, ENVIRONMENTAL REGULATIONS AND ELECTRIC SYSTEM RELIABILITY (June 2011), *available at* http://www.bipartisanpolicy.org/sites/default/files/BPC%20Electric%20System%20Reliability.pdf; PJM INTERCONNECTION, COAL CAPACITY AT RISK FOR RETIREMENT IN PJM (Aug. 2011), *available at* http://pjm.com/~/media/documents/reports/20110826-coal-capacity-at-risk-for-retirement.ashx; STEVEN FINE ET AL., ICF INTERNATIONAL, POTENTIAL IMPACTS OF ENVIRONMENTAL REGULATION ON THE U.S. GENERATION FLEET (EDISON ELECTRIC INSTITUTE Jan. 2011), *available at* http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2011IRP/EEIModelingReportFinal-28January2011.pdf; MICHAEL J. BRADLEY ET AL., M. J. BRADLEY & ASSOCIATES LLC, ENSURING A CLEAN, MODERN ELECTRIC GENERATING FLEET WHILE MAINTAINING ELECTRIC SYSTEM RELIABILITY (Aug. 2010), *available at*

unlikely to impact reliability, while other studies predict a significant and near-certain impact on reliability. Congress has taken an interest in the issue, as evidenced by a series of correspondence between FERC and relevant Committees of the U.S. House and Senate.[41]

On November 29 and 30, 2011, FERC held its third annual reliability technical conference, where FERC devoted an entire panel to discussing the impact of EPA regulations on electric-grid reliability.[42] An EPA representative testified as to the health and safety benefits of the proposed regulations.[43] In their written and spoken testimonies, panelists from the electric utility industry indicated that a three-year compliance window is too short to avoid imposing significant risks on the reliability of the electric grid, and suggested longer compliance deadlines.[44] The final Utility Maximum Achievable Control Technology (MACT) rule was signed on December 16, 2011, and the rule was unveiled by EPA Administrator Lisa Jackson at a Washington, D.C., hospital on December 21, 2011.[45]

3. Smart Grid

Under the Energy Independence and Security Act of 2007, the National Institute of Standards and Technology (NIST) was charged with "responsibility to coordinate the development of a framework … to achieve interoperability of smart grid devices and systems."[46] In so doing, NIST was directed under the Act to "seek input and cooperation" from FERC, NERC, DOE's Office of Electricity Delivery and Energy Reliability, the Smart Grid Task Force, the Smart Grid Advisory Committee, the Gridwise Architecture Council, International Electrical and Electronics Engineers (IEEE), the National Electrical Manufacturers Association (NEMA), and other relevant federal and state agencies and private entities.[47] In response, NIST established the Smart Grid

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http://www.mjbradley.com/sites/default/files/MJBAandAnalysisGroupReliabilityReportAugust2010.pdf.

[41] *See, e.g.*, Letter from House Comm. on Energy and Commerce, to Steven Chu, Sec'y of DOE and Jon Wellinghoff, Chairman of FERC (May 9, 2011); Letter from Lisa Murkowski, Senate Comm. on Energy and Natural Res., to Jon Wellinghoff, Chairman of FERC (May 17, 2011); Letter from Jon Wellinghoff, Chairman of FERC, to Fred Upton, Chairman of House Comm. (July 27, 2011).

[42] Reliability Technical Conference, FERC Docket Nos. AD12-1-000, RC11-6-000, EL11-62-000 (Nov. 9, 2011). Details and documents from the technical conference *available at* http://www.ferc.gov/EventCalendar/EventDetails.aspx?ID=6053&CalType=%20&CalendarID=116&Date=11/29/2011&View=Listview.

[43] *See, e.g.*, Statement of Regina McCarthy, Assistant Adm'r, Office of Air and Radiation, EPA, FERC Docket No. AD12-1-000 at 1-2 (Nov. 30, 2011).

[44] *See generally* Statement of Anthony Topazi, S. Co. Servs., Inc.; Nicholas K. Askins, Am. Elec. Power; William J. Gallagher, NERC; Mike Smith, Ga. Transmission Corp., to FERC Reliability Technical Conference, Docket No. AD12-1-000 (Nov. 29-30, 2011).

[45] *See* Press Release, EPA, EPA Adm'r Jackson to Make Significant Clean Air Act Announcement (Dec. 20, 2011), *available at* http://yosemite.epa.gov/opa/admpress.nsf/1e5ab1124055f3b28525781f0042ed40/c33fd4dafb97796f8525796c006a3b04!OpenDocument; Mark Drajem, *EPA Mercury Rule for Power Plants to be Unveiled at Hospital*, BUS. WK. (Dec. 20, 2011), *available at* http://www.businessweek.com/news/2011-12-20/epa-mercury-rule-for-power-plants-to-be-unveiled-at-hospital.html.

[46] 42 U.S.C. § 17385(a) (Supp. 4 2010).

[47] *Id.*

Interoperability Panel (SGIP) as a forum in which to coordinate the development of smart grid standards.[48] Under the Act, after NIST's work "has led to sufficient consensus in [FERC's] judgment, [FERC] shall institute a rulemaking proceeding to adopt such standards and protocols as may be necessary to insure smart-grid functionality and interoperability in interstate transmission of electric power, and regional and wholesale electricity markets."[49] Meanwhile, on July 16, 2009, FERC issued a Policy Statement that outlined its own six key priorities for the development of smart grid standards: (1) system security, (2) communication and coordination across inter-system interfaces, (3) wide-area situational awareness, (4) demand response, (5) electricity storage, and (6) electric vehicles.[50] In October 2010, NIST advised FERC that it had identified five families of smart grid standards that were ready for review and consideration by FERC.[51]

On January 31, 2011, in Docket No. RM11-2-000, FERC held a technical conference to examine whether there was sufficient consensus that NIST's five families of standards were ready for FERC's consideration in a rulemaking proceeding, as required by the Act. In the technical conference, panelists opined that no consensus had been reached on interoperability standards, and that the SGIP process needed refining. They also emphasized that the interoperability standards should be voluntary and not mandatory. On February 16, 2011, FERC issued a supplemental notice requesting comments, and on July 19, 2011 FERC issued a decision in which it found insufficient consensus on smart grid interoperability standards. Therefore, FERC declined to institute a rulemaking, and terminated the docket. FERC encouraged stakeholders to actively participate in the SGIP process, and to refer to that process for guidance on smart grid standards.[52]

In August 2011, SGIP made its first six entries in its Catalog of Standards. According to SGIP, the Catalog of Standards is a collection of "standards, guides, and other specifications recognized by the SGIP as relevant for enabling Smart Grid capabilities."[53] However, inclusion in the Catalog of Standards does not imply consensus: "no endorsement, beyond that of relevancy, is implied by inclusion in the Catalog."[54]

On September 8, 2011, the Subcommittee on Technology and Innovation of the House Science Committee held a hearing on smart grid standards. In his opening statement, Committee Chairman Ben Quayle expressed his concern with the idea of mandatory standards, when voluntary standards could be sufficient to ensure interoperability.[55] He also expressed interest in how "a smarter grid could enable small

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[48]*See* SMART GRID INTEROPERABILITY PANEL, http://www.sgipweb.org (last visited Feb. 12, 2012).

[49]42 U.S.C. § 17385(d).

[50]*Smart Grid Policy*, 128 FERC ¶ 61,060, Docket No. PL09-4-000 at PP 29-94 (July 16, 2009) (to be codified at 18 C.F.R. Chapter I), *available at* http://www.ferc.gov/whats-new/comm-meet/2009/071609/E-3.pdf.

[51]Press Release, NIST, NIST Identifies Five "Foundational" Smart Grid Standards (Oct. 7, 2010), *available at* http://www.nist.gov/public_affairs/releases/smartgrid_100710.cfm.

[52]*Order on Smart Grid Interoperability Standards*, 136 FERC ¶ 61,039, at P 1-2, 5-6, 8, 10, 13 (2011).

[53]Marty Burns, *SGIP Catalog of Standards*, NIST (FEB. 22, 2012, 2:06 PM), http://collaborate.nist.gov/twiki-sggrid/bin/view/SmartGrid/SGIPCatalogOfStandards#Overview?create=on&newtopic=SGIPCatalogOfStandards#Overview&template=WebCreateNewTopic&topicparent (last updated Dec. 22, 2011).

[54]*Id.*

[55]*Empowering Consumers and Promoting Innovation Through the Smart Grid*, 112th Cong. (Sept. 8, 2011) (opening statement of Rep. Ben Quayle, Chairman, Subcomm. on Tech. and Innovation), *available at*

companies to develop new products based on a transparent standards platform that is available to all innovators," and in how "the updated grid could allow small generators and intermittent renewable energy sources to play a larger role in our electrical system."[56]

On October 26, 2011, NIST issued the second draft of its Smart Grid Framework.[57] New elements added to the first draft included an expanded list of standards, new cyber security guidance, and product testing proposals. Further stated improvements included (1) an expanded view of the architecture of the smart grid; (2) a number of developments related to ensuring cyber security for the smart grid, including a Risk Management Framework to provide guidance on security practices; (3) a new framework, as contained in the Interoperability Process Reference Manual, for testing the conformity of devices and systems to be connected to the smart grid; (4) information on efforts to coordinate U.S. smart grid standards development with similar development programs in other parts of the world; and (5) an overview of future areas of work, including electromagnetic disturbance and interference; and, importantly, improvements to SGIP processes.[58]

4. Demand Response Compensation in Organized Wholesale Electricity Markets

FERC has declared that demand response resources should be given comparable treatment and priority as that given to other generation resources. As discussed above, Order No. 1000 requires public utility transmission providers to consider all types of resources, including demand response and energy efficiency, on a comparable basis in transmission planning.[59] In addition, in 2011 FERC issued important orders on demand response issues.

On March 15, 2011, in Docket No. RM10-17-000, FERC issued Order No. 745 regarding demand response compensation in organized wholesale energy markets administered by regional transmission organizations (RTOs) or independent system operators (ISOs).[60] Order No. 745 requires RTOs and ISOs to pay demand response resources participating in the day-ahead and real-time wholesale energy markets the locational marginal price (LMP) when two conditions are met: (1) demand response resources must be capable of balancing supply and demand in the wholesale energy markets, and (2) dispatching and paying LMP to demand response resources must be cost effective under a net benefits test.[61]

FERC received several requests for rehearing. On May 13, 2011, FERC issued a tolling order granting the requests for rehearing for further consideration.[62] On June 27,

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http://science.house.gov/sites/republicans.science.house.gov/files/documents/hearings/090811_quayle.pdf.

[56] *Id*.

[57] *See* NIST, DRAFT NIST FRAMEWORK AND ROADMAP FOR SMART GRID INTEROPERABILITY STANDARDS, RELEASE 2.0, (Oct. 17, 2011), *available at* http://collaborate.nist.gov/twikisggrid/pub/SmartGrid/IKBFramework/Draft_NIST_Framework_Release_2-0_10-17-2011.pdf.

[58] *Id.* at 6-7, 10-13.

[59] Final Rule, *supra* note 2, at PP 153-154.

[60] *Demand Response Compensation in Organized Wholesale Energy Markets*, 134 FERC ¶ 61,187 at P 1 (2011).

[61] *Id.* at P 3.

[62] *Order Granting Rehearing for Further Consideration*, FERC Docket No. RM10-17-001 (May 13, 2011). The tolling order gives FERC time to review the requests for rehearing and possibly reverse, affirm, or change its initial determinations.

2011, ISO New England requested an extension of time to submit a compliance filing pursuant to Order No. 745:

> [T]o produce a compliance package that takes into consideration important views of its stakeholders and that is more likely to have the support of the region's stakeholders and state regulators. The additional time will be used to schedule at least one additional [New England Power Pool] Markets Committee meeting cycle during which [ISO New England] will consider additional feedback, revise proposed market rules and present the revised rules for review and voting purposes.[63]

On December 15, 2011, FERC issued Order No. 745-A in response to the requests for rehearing and clarification.[64] With Commissioner Moeller dissenting, FERC denied the requests for rehearing, and granted in part and denied in part the requests for clarification.[65] In his dissent, Commissioner Moeller stated the following:

> [I]t has become clear since the issuance of Order No. 745 that my earlier concerns in this proceeding were justified. Namely, rather than impose a nationwide approach to demand response compensation, [FERC's] objective of promoting demand response would have been better served if the regions were free to propose compensation methods that recognize the very real differences in the structures of the regional markets. In addition, the evidence now shows that the Net Benefits Test will be so costly to develop and so difficult to administer that it can be expected to result in an allocation of the costs of demand response to the parties that do not benefit from demand response. Therefore, rather than continuing to pursue demand response compensation at full LMP only when the Net Benefits Test is passed, I would have changed that decision and put in its place compensation at LMP–G, where "G" is the avoided retail cost of generation.[66]

5. FERC National Action Plan on Demand Response

In November 2011, FERC staff issued an *Assessment of Demand Response and Advanced Metering Staff Report* (DR Report).[67] The DR Report is completed annually, as required by section 1252(e)(3) of the Energy Policy Act of 2005,[68] and assesses electricity demand response resources. Based on a review of various sources that provide information on demand response and advanced metering results, activities, and regulatory actions, FERC staff observed that:

> [i] [t]he penetration of advanced meters is up from 8.7 percent in 2009 to 13.4 percent; [ii] [d]emand response potential in organized markets

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[63]*Motion of ISO New England, Inc. Requesting Extension of Time to Submit Compliance Filing*, FERC Docket No. RM10-17-001 (June 27, 2011).
[64]*Order on Rehearing and Clarification*, Order No. 745-A, FERC Docket No. RM10-17-001 (Dec. 15, 2011).
[65]*Id*. at p. 56.
[66]*Id*. at p. 1.
[67]DAVID KATHAN ET AT., FERC, ASSESSMENT OF DEMAND RESPONSE AND ADVANCED METERING (Nov. 2011) [hereinafter DR Report], *available at* http://www.ferc.gov/legal/staff-reports/11-07-11-demand-response.pdf.
[68]Energy Policy Act of 2005, Pub. L. No. 109-58, § 1252(e)(3), 119 Stat. 594 (2005).

operated by the Electric Reliability Council of Texas (ERCOT), [RTOs], and [ISOs] increased by more than 16 percent since 2009; [iii] [d]emand responded to peak load emergency conditions in ERCOT and the RTO and ISO organized markets; and [iv] [f]ederal and state regulators and others continue to focus on demand response, taking actions to remove barriers to wholesale demand response and develop policies to address smart grid.[69]

6. Regulation Compensation in RTOs

On October 20, 2011, FERC issued Order No. 755, which addresses frequency regulation compensation in RTOs and organized wholesale electricity markets.[70] In Order No. 755, FERC found that the current frequency regulation compensation practices of RTOs and ISOs resulted in unjust and discriminatory rates.[71] Specifically, FERC found that the compensation methods for regulation service in RTO and ISO markets fail to acknowledge the "inherently greater amount of frequency regulation service being provided by faster-ramping resources."[72] Order No. 755 requires RTOs and ISOs to compensate frequency regulation resources "based on the actual service provided, including a capacity payment that includes the marginal unit's opportunity costs and a payment for performance that reflects the quantity of frequency regulation service provided by a resource when the resource is accurately following the dispatch signal."[73]

On November 21, 2011, Southern California Edison requested clarification or, in the alternative, rehearing of Order No. 755.[74] Also on November 21, 2011, ISO New England requested an extension of time for implementing the revised provisions in order to develop necessary software changes and associated business procedures.[75] On December 13, 2011, FERC denied ISO New England's request for an extension of time. On December 19, 2011, FERC issued a tolling order granting rehearing for further consideration.[76]

B. State Developments

1. Continuing State Efforts to Promote Renewable Generation

Currently, twenty-nine states, plus Washington, D.C. and Puerto Rico, have some form of renewable portfolio standard (RPS) program in effect.[77] In addition, eight states have voluntary renewable portfolio goals in effect.[78] Renewable generation, excluding

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[69]DR Report, *supra* note 58, at p. 1. Note that the DR Report provides a summary of state legislative and regulatory activity related to demand response at page 16.
[70]Final Rule, 137 FERC ¶ 61,064 (October 20, 2011), FERC STATS & REGS ¶ 31,324 (2011), 76 Fed. Reg. 67,260 (2011).
[71]*Id.* at PP 1-2.
[72]*Id.* at P 2.
[73]*Id.* at P 3.
[74]*Request for Clarification*, FERC Docket Nos. RM11-7-000, AD10-11-000 (Nov. 21, 2011).
[75]*Motion for Extensions*, FERC Docket Nos. RM11-7-000, AD10-11-000 (Nov. 21, 2011).
[76]*Order Granting Rehearing for Further Consideration*, FERC Docket Nos. RM11-7-001, AD10-11-001 (Dec. 19, 2011).
[77]DSIRE, *RPS Policies Map*, DOE (Jan. 2012), http://www.dsireusa.org/documents/summarymaps/RPS_map.ppt. RPS programs are also commonly referred to as Renewable Energy Standard (RES) programs.
[78]*Id.*

hydroelectricity, comprises 4.9% of total domestic electricity generation through year-to-date August 2011, which marks an increase of 0.4% over the prior year.[79] Existing RPS programs apply to 50% of U.S. electricity load in 2011.[80]

States employ a multitude of policy tools to promote renewable development including RPS programs, tax incentives, grants, loans and loan financing support, net metering programs, feed-in-tariffs (FITs), and production incentives. Generally, RPS programs obligate retail electricity suppliers to procure a minimum percentage of delivered electricity from eligible sources of renewable energy.[81] Programs vary in the percentage of procurement, the various "Tiers," and in the eligible generation technologies. RPS programs are typically backed with penalties for non-compliance, referred to as Alternative Compliance Payments (ACP), and are often accompanied by a tradable renewable energy certificate or credit (REC) program to facilitate compliance. RPS policies are increasingly being designed to support resource diversity. For example, many states require that some portion of RPS compliance come from specific renewable resource technologies or applications. Enactment of new state RPS policies is waning, although several states took steps during 2011 to modify existing programs. For example, several states changed their Tier definitions or targets, changed their ACP, or enabled new types of resources to qualify under various renewable resource classifications.[82]

a. Renewable Portfolio Standards in the Northeast

In July 2011, with the passage of S.B. 124, Delaware amended its RPS to allow for certain fuel cells to qualify under the solar tier (Tier II) of its RPS.[83] Washington, D.C. updated its annual compliance percentages for the solar carve-out (Tier III), in accordance with newly enacted B19-10, which increased the standard from 0.4% by 2020 to 2.5% by 2023.[84] With the passage of SB 690, Maryland expanded the types of facilities that may qualify as eligible facilities and reclassified waste-to-energy from a Tier II to a

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[79] U.S. ENERGY INFO. ADMIN. (EIA) & DOE, DOE/EIA-0226 (2011/11), ELECTRIC POWER MONTHLY, NOV. 2011 at 1, *available at* http://www.eia.gov/electricity/monthly/current_year/november2011.pdf. The total domestic electricity generation through year-end 2010 was 4.5%. EIA & DOE, DOE/EIA-0226 (2011/01), ELECTRIC POWER MONTHLY, JANUARY 2011 at 19-21, *available at* http://www.eia.gov/electricity/monthly/current_year/january2011.pdf.

[80] *2011 National Summit on RPS* at 7, State-Federal RPS Collaborative (Oct. 26, 2011), *available at* www.cleanenergystates.org/assets/Uploads/2011-RPS-Summit-Combined-Presentations-File.pdf.

[81] This method is followed by the vast majority of states with RPS programs. Other states such as New York and Illinois follow a "central procurement" model. In New York the state RPS is administered by the New York State Energy Research and Development Authority (NYSERDA). NYSERDA fulfills the RPS by a combination of auction, requests for proposals (RFPs), and standard offer contracts. *Id.* at 11.

[82] *Id.* at 4-34.

[83] S. 124, 146th Gen. Assemb., 78 Del. Laws 99 (2011). *available at* http://www.legis.delaware.gov/LIS/lis146.nsf/vwLegislation/SB+124/$file/legis.html?open. On September 6, 2011, the Delaware PSC entered Order No. 8026 reopening Regulation Docket No. 56 and proposing amendments to the Delaware RPS. *Delaware's Renewable Portfolio Standard, Delaware Public Service Commission,* http://depsc.delaware.gov/electric/delrps.shtml (last updated Feb. 6, 2012).

[84] *District of Columbia Renewables Portfolio Standard,* DSIRE, http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=DC04R&RE=1&EE=1.

Tier I resource.[85] With SB 717, Maryland now allows solar water heating to qualify for the solar carve-out.[86]

b. Renewable Portfolio Standards in the Midwest

In 2011, the Midwest saw minor changes in RPS programs, except for the notable implementation of a voluntary program in Indiana.[87] Illinois amended the Illinois Power Agency Act with a distributed generation requirement, whereby the agency must procure distributed generation in addition to renewable energy.[88] Illinois also amended its definition of "renewable energy resources" to include biogas and bio-solids produced by municipal wastewater treatment plants.[89]

In Minnesota, the RPS was revised to allow the Minnesota Public Utility Commission to impose an administrative penalty on public utilities for non-compliance, the amount of which may not exceed the estimated costs of compliance.[90] Public utilities also must now estimate and report the rate impact of activities necessary to comply with Renewable Energy Objectives.[91] Minnesota also expanded the list of eligible fuels under the RPS to include facilities that use mixed municipal solid waste.[92] In Wisconsin, the legislature expanded the definition of "renewable resources" to include energy produced by hydroelectric facilities in Canada.[93] As of year-end 2011, the Michigan Public Service Commission was in the process of finalizing the administrative rules governing Michigan's renewable energy and energy optimization standards.[94]

c. Renewable Portfolio Standards in California

In 2011, new legislation increased California's RPS mandate from 20% by 2010 to 33% by 2020.[95] The legislation also codified restrictions on the use of RECs procured from projects that are not interconnected to the California electric grid, by requiring that 75% of the energy procured for RPS compliance purposes must come from projects that

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85 *Maryland Renewable Energy Portfolio Standard,* DSIRE, http://dsireusa.org/incentives/incentive.cfm?Incentive_Code=MD05R (last visited Feb. 17, 2012).
86 *Id.*
87 IND. CODE § 8-1-37-1 to -14 (2011), *available at* http://www.in.gov/legislative/ic/code/title8/ar1/ch37.html.
88 *Illinois Renewable Portfolio Standard,* DSIRE, http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=IL04R (last visited Feb. 17, 2012); 20 ILL. COMP. STAT. 3855/1-10, 1-56, 1-75 (2011), *available at* http://www.ilga.gov/legislation/97/SB/PDF/09700SB1652lv.pdf.
89 *Id.* at 6.
90 MINN. STAT. § 216B.1691 Subd. 7 (2011), *available at* https://www.revisor.mn.gov/statutes/?id=216B.1691.
91 *Id.* at Subd. 2e.
92 *Id.* at Subd. 1(5).
93 WIS. STAT. § 196.378(2)(b)(1o) (2011), *available at* https://docs.legis.wisconsin.gov/statutes/statutes/196/378.
94 *Michigan Renewable Energy Standard*, DSIRE, http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=MI16R&re=1&ee=1 (last visited Feb. 11, 2011).
95 S. X1-2, 1st Ext. Sess. (Cal. 2011), *available at* http://www.leginfo.ca.gov/pub/11-12/bill/sen/sb_0001-0050/sbx1_2_bill_20110412_chaptered.html.

are directly interconnected to the California grid, or from out-of-state sources that employ "dynamic transfer" transmission arrangements.[96]

California's three largest investor owned utilities (IOUs) reported that in 2010 17.0% of the electricity delivered to end-users was procured from renewable resources.[97] In 2011, an estimated 1000MW of new renewable capacity will have been placed in service.[98] This increase in renewable capacity represents the largest single-year increase since the California RPS program was established in 2002.[99]

As part of his Green Jobs Plan, Governor Jerry Brown established a new goal of procuring 12,000MW of RPS capacity from distributed generation resources, defined as projects of 20MW or less that do not require significant new investment in transmission infrastructure.[100] Stakeholders are presently working with State regulators to review distribution interconnection procedures and determine what regulatory changes are necessary to facilitate the interconnection and integration of significant amounts of new distributed generation.[101]

The California legislature has taken steps to streamline the permitting process for renewable generation, a process which is frequently blamed for impeding timely project development and discouraging investment. New legislation streamlines endangered species review for renewable projects in certain sensitive desert areas; shortens the period for judicial review of legal challenges to land use entitlements for large renewable projects; exempts from environmental review for rooftop and parking lot solar; clarifies water supply assessments for certain renewable projects; and facilitates solar development on marginally productive or physically impaired agricultural lands.[102]

2. Curtailment of Renewable Resources

State and Regional Curtailment and Demand Response Programs

Many states or Regional Transmission Organizations/Independent System Operators (RTO/ISO) regions provide incentives to curtail electric demand during peak usage periods in response to system reliability or market conditions. The DOE has

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[96]CAL. PUB. UTIL. COMM'N, 4Q 2011 RPS QUARTERLY REPORT at 1, 6, *available at* http://www.cpuc.ca.gov/NR/rdonlyres/3B3FE98B-D833-428A-B606-47C9B64B7A89/0/Q4RPSReporttotheLegislatureFINAL3.pdf.
[97]CAL. PUB. UTIL. COMM'N, 3Q 2011 RPS QUARTERLY REPORT at 2, *available at* http://www.cpuc.ca.gov/NR/rdonlyres/2A2D457A-CD21-46B3-A2D7-757A36CA20B3/0/Q3RPSReporttotheLegislatureFINAL.pdf.
[98]*Id.*
[99]*Id*. at 3 (Fig. 1).
[100]Memorandum from Governor Scott Brown on Renewable Energy, at 2 (Oct. 12, 2011), *available at* http://www.drecp.org/meetings/2011-10-12_meeting/presentations/Governor_Brown_Renewable_Energy_Statement_10-12-2011.pdf.
[101]*Id.* at 5-7.
[102]Dian Grueneich et al., *2011 Renewable Energy Legislation,* MORRISON & FOERSTER LLP, at 1 (Sept. 13, 2011) http://www.mofo.com/files/Uploads/Images/110913-2011-California-Renewable-Energy-Legislation-Watershed-Year.pdf (summarizing A.B. 13, 1st Ext. Sess. (Cal. 2011), A.B. 900, Reg. Sess. (Cal. 2011), S. 226, Reg. Sess. (Cal. 2011), S. 267, Reg. Sess. (Cal. 2011), & S. 618, Reg. Sess. (Cal. 2011).

compiled and posted on its website nationwide demand response and load management program information.[103]

a. MISO's implementation of Dispatchable Intermittent Resources

In 2011, the Midwest Independent Transmission System Operator, Inc., (MISO) offered to renewable power producers an opportunity to participate in the MISO real-time energy market as a Dispatchable Intermittent Resource (DIR). The purpose of the new DIR designation is to allow for wind and other intermittent resources to be offered into the market and receive dispatch instructions based on the offer price instead of being manually curtailed based on MISO cost signals or locational marginal price (LMP).[104]

While it may be too early to determine whether MISO's DIR tariff allows renewable power producers to more efficiently dispatch their energy, MidAmerican Energy submitted a report to MISO in October 2011 that conveys its belief that the benefits of DIR will outweigh the costs.[105] MidAmerican Energy's belief is based on realized benefits including lower Revenue Sufficiency Guarantee payments and less dramatic swings in dispatch levels.

3. State Initiatives to Increase In-State Capacity in the PJM Region

In 2011, citing concerns about the price of electricity for their citizens and the need for additional capacity, two states within the PJM Interconnection L.L.C. (PJM) region undertook measures to promote the development of additional in-state capacity. New Jersey passed a measure designed to procure approximately 2,000MW of capacity outside of the PJM wholesale markets through a long-term capacity agreement pilot program,[106] and Maryland proposed to issue a solicitation for approximately 1,800MW of new capacity with which utilities would be required to contract.[107]

Subsequently, a group of generators in PJM filed a complaint with FERC arguing that the actions taken by New Jersey and Maryland would suppress capacity prices in PJM's reliability pricing model wholesale auctions.[108] Shortly thereafter, PJM submitted a filing to FERC proposing to drop an exemption for state-sponsored gas-fired generation

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[103]*See Energy Incentive Programs,* FED. ENERGY MGMT. PROG., http://www1.eere.energy.gov/femp/financing/energyincentiveprograms.html (last visited Feb. 11, 2012).

[104]Press Release, MISO, MISO Furthers Wind Integration Into Market (June 1, 2011), *available at* https://www.midwestiso.org/AboutUs/MediaCenter/PressReleases/Pages/MISOFurthersIntegrationofWindResources.aspx.

[105]Peggy Allenback, MidAm. Energy, MISO Dispatchable Intermittent Res. Workshop at 4-5 (Oct. 17, 2011), *available at* https://www.midwestiso.org/Library/Repository/Meeting%20Material/Stakeholder/Workshop%20Materials/DIR%20Workshops/20111017%20DIR%20Workshop%20MidAmerican%20Presentation.pdf.

[106]S. 2381, 214th Leg. (N.J. 2011), *available at* http://www.njleg.state.nj.us/2010/Bills/S2500/2381_R1.HTM.

[107]In re Whether New Generating Facilities Are Needed to Meet Long-Term Demand for Standard Offer Service, No. 9214 (Md. Pub. Serv. Comm'n Dec. 29, 2010), *available at* http://webapp.psc.state.md.us/Intranet/Casenum/CaseAction.cfm?CaseNumber=9214.

[108]Complaint and Request for Clarification Requesting Fast Track Processing at 60, 65, FERC Docket No. EL11-20-000 (Feb. 1, 2011); *see also PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,022 at P 2 (2011), *available at* http://elibrary.ferc.gov/idmws/File_list.asp?document_id=13909219.

from the minimum offer price rule (MOPR), which imposes a minimum offer screen to determine whether an offer from a new resource is competitive.[109] FERC issued an order on April 12, 2011 accepting PJM's proposed MOPR changes.[110]

Through a final order issued on November 17, 2011, FERC denied New Jersey and Maryland regulators' requests for rehearing of its April 2011 decision.[111] In the November Order, FERC generally affirmed its acceptance of PJM's proposed revisions to the MOPR, finding that the MOPR "serves a critical function to ensure that wholesale prices are just and reasonable and should elicit new entry when new capacity is needed."[112] While FERC generally rejected requests for rehearing, it did grant rehearing to provide that parties are not limited to using the nominal levelized financial modeling methodology in their efforts to justify their sell offers in the MOPR case-specific review process.[113]

We expect further developments during 2012. On November 28, 2011, the PJM Power Providers Group (P3) and PSEG Energy Resources & Trade LLC submitted separate Petitions for Review of FERC's April 12 and November 17 Orders to the United States Court of Appeals for the District of Columbia Circuit.[114] In December of 2011, the New Jersey Board of Public Utilities (NJ BPU) and the New Jersey Division of Rate Counsel as well as the Maryland Public Service Commission filed separate Petitions for Review with the US Court of Appeals for the Third Circuit.[115]

II. NATURAL GAS DEVELOPMENTS

A. *FERC Enforcement Actions Under Natural Gas Act Section 5*

On November 17, 2011, FERC opened investigations under section 5 of the Natural Gas Act[116] into rates charged by three interstate natural gas companies: ANR Storage Co., Bear Creek Storage Company LLC, and MIGC LLC.[117] FERC alleges that the pipeline companies may be over-recovering their costs, resulting in unjust and unreasonable rates based on a preliminary investigation by FERC Staff into the companies' Form 2 cost and revenue data. This is the third consecutive year that the

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[109] 135 FERC ¶ 61,022 at P 1, 6.
[110] *Id.* at P 3.
[111] *PJM Interconnection, L.L.C.*, 137 FERC ¶ 61,145 at P 23 (2011) (Nov. 17 Order), *available at* http://elibrary.ferc.gov/idmws/File_list.asp?document_id=13972179.
[112] *Id.* at P 2.
[113] *Id.* at P 33.
[114] Petition for Review of PJM Power Providers Group, PJM Power Providers Group v. FERC, No. 11-1455 (D.C. Cir. filed Nov. 28, 2011), *available at* http://elibrary.ferc.gov/idmws/File_list.asp?document_id=13974552; Petition for Review of PSEG Energy Res. & Trade L.L.C., PSEG Energy Res. & Trade L.L.C., v. FERC, No. 11-1456 (D.C. Cir. Filed Nov. 28, 2011), *available at* http://elibrary.ferc.gov/idmws/File_list.asp?document_id=13974514.
[115] *See e.g.*, Petition for Review, Maryland Pub. Serv. Comm'n v. FERC (3d Cir. filed Dec. 13, 2011), *available at* http://elibrary.ferc.gov/idmws/File_list.asp?document_id=13979997.
[116] 15 U.S.C. § 717d (2006).
[117] *ANR Storage Co.*, 137 FERC ¶ 61,136 (2011), *available at* http://www.ferc.gov/whats-new/comm-meet/2011/111711/G-4.pdf; *Bear Creek Storage, L.L.C.*, 137 FERC ¶ 61,134 (2011) *available at* http://www.ferc.gov/whats-new/comm-meet/2011/111711/G-2.pdf; *MIGC LLC*, 137 FERC ¶ 61,135 (2011) *available at* http://www.ferc.gov/whats-new/comm-meet/2011/111711/G-3.pdf.

Commission has invoked its section 5 authority to investigate natural gas pipeline rates.[118] The investigations have been informed by revisions to the Form 2 data, which were mandated in Order No. 710,[119] issued in March 2008, and require pipelines to file more detailed information. Earlier this year, the Commission settled with Kinder Morgan Interstate Gas Transmission LLC and Ozark Gas Transmission, L.L.C., two pipelines it filed section 5 proceedings against in 2010.

B. Liquefied Natural Gas Export Authorizations and Requests

In 2011, five domestic liquefied natural gas (LNG) import terminals sought authorization from the Office of Fossil Energy of the DOE to become exporting terminals, to facilitate the export of U.S. natural gas.[120] The export applications demonstrate one impact that shale gas has had on the domestic natural gas market. Until recently, LNG was considered an essential component of the U.S. energy mix. However, the influx of domestically-produced shale gas has flattened domestic natural gas prices. On May 20, 2011, Sabine Pass became the first LNG terminal to obtain conditional export authorization.[121] This is significant because it is the first time that DOE has authorized the long-term export of domestically produced natural gas from the lower-48 states to countries without a free trade agreement with the U.S.[122] The conditional authorization reserves for DOE the ability to revisit its authorization at any time. The DOE also stated that it would "monitor" such conditions to "ensure that the exports of LNG authorized herein and in any future authorizations of natural gas exports do not subsequently lead to a reduction in the supply of natural gas needed to meet essential domestic needs."[123]

C. Gas/Electric Convergence Lessons Learned from Southwest Cold Weather Event

On February 1-5, 2011, frigid weather in the U.S. Southwest impacted natural gas supply in the region, shutting power plants and causing rolling blackouts.[124] The cold weather event highlighted the growing interdependency of electricity and natural gas.[125]

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[118] 137 FERC ¶ 61,135 at P 1, 5.

[119] *Id.* at P 4; Final Rule, *Revisions to Forms, Statements, and Reporting Requirements for Natural Gas Pipelines*, 122 FERC ¶ 61,262, at P 1 (Mar. 21, 2008), FERC Stats & Regs. ¶31,26773, 73 Fed. Reg. 19,389, (2008), *available at* http://www.ferc.gov/whats-new/comm-meet/2008/032008/M-2.pdf.

[120] Dominion Cove Point LNG, LP (Lusby, Maryland), Freeport LNG Development, L.P. (Freeport, Texas), Lake Charles Exports, LLC (Lake Charles, Louisiana), Jordan Cove Energy Project, L.P. (Coos Bay, Oregon), and Sabine Pass Liquefaction, LLC (Cameron Parish, Louisiana) (Sabine Pass) applications are available on the DOE's website. *Natural Gas Import & Export Regulation*, DOE http://www.fossil.energy.gov/programs/gasregulation/index.html (last visited Feb. 19, 2012).

[121] Opinion and Order at 42, Sabine Pass Liquefication, LLC, FE Docket No. 10-111-LNG (May 20, 2011), *available at* http://www.fossil.energy.gov/programs/gasregulation/authorizations/Orders_Issued_2011/ord2961.pdf.

[122] *Id.* at 20.

[123] *Id.* at 32.

[124] FERC & NERC, REPORT ON OUTAGES AND CURTAILMENTS DURING THE SOUTHWEST COLD WEATHER EVENT OF FEBRUARY 1-5, 2011, at 159 (Aug. 2011), *available at* http://www.nerc.com/files/SW_Cold_Weather_Event_Final_Report.pdf.

[125] *Id.* at 189.

FERC and NERC investigated the incident to determine the causes, including convergence issues between the electric and natural gas industries, and issued a report.[126] According to the joint staff report, communications failures between operators of natural gas and electric facilities did not play a role during the February 2011 event.[127] Nonetheless, the report suggests that the two industries revisit recommendations made by a 2004 Gas/Electricity Interdependency Task Force. "NERC [also] plans to conduct an electric/gas interdependency study . . . to reevaluate the GEITF recommendations. The study will analyze whether procedures should be developed for communications between the electric and [natural] gas industries."[128]

III. COMMODITIES DEVELOPMENTS

A. Dodd-Frank Act Developments

The Commodity Futures Trading Commission (CFTC) continued promulgating rules and issuing Notices of Proposed Rulemakings (NOPRs) under Title VII of the Dodd-Frank Act (DFA). Several of these could significantly impact energy and the environment.

1. Scope

The securities law reforms of the 1930s generally prohibit transactions in securities unless such securities are registered with the Securities and Exchange Commission (SEC) or exempt from registration. One could conceptually analogize that DFA requires "swaps" to be cleared unless complying with a regulatory apparatus designed to discourage un-cleared swaps.[129] The bounds of the regulated conduct are not yet fully clear, but central to them is the definition of a "swap." The CFTC's Swaps Definition NOPR[130] implies federal jurisdiction over most transactions for the purchase and sale of goods and services not within limited exceptions, by providing an interpretive guidance that "purchase, sale, lease, or transfer of real property, intellectual property, equipment, or inventory"[131] would not be considered swaps. The CFTC also invites parties "to seek an interpretation from [CFTC] as to whether the agreement, contract, or transaction is a swap,"[132] but nevertheless providing that all full-requirements commodity purchase and sale contracts, and all commodity contracts with evergreen or extension

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[126] *Id.* at 1.
[127] *Id.* at 194.
[128] *Id.* at 194, n.263.
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> Another approach to regulating the OTC market . . . would be to increase the cost of OTC transactions in the hope that participants would shift them to exchanges or clearinghouses. [DFA] does that by raising capital requirements . . . and by increasing margin requirements for institutions that trade in OTC contracts. . . . The resulting increase in compliance costs for OTC transactions is designed to serve as an incentive to standardize contracts and move them onto exchanges or clearing houses.

CBO, EVALUATING LIMITS ON PARTICIPATION AND TRANSACTIONS IN MARKETS FOR EMISSIONS ALLOWANCES at 15 (Dec. 2010), *available at* http://www.cbo.gov/ftpdocs/120xx/doc12006/12-10-LimitsAllowanceMarkets.pdf.
[130] 76 Fed. Reg. 29,818 (May 23, 2011), *available at* http://www.gpo.gov/fdsys/pkg/FR-2011-05-23/pdf/2011-11008.pdf.
[131] *Id.* at 29,833.
[132] *Id.*

terms, would be regulated by CFTC.[133] Therefore, unless limited in the final rule, a large swath of U.S. commerce, from consumption of electricity by an aluminum mill, to water use by a feedlot, to power purchase agreements with renewal terms, would be subject to DFA.

2. "Anti-Evasion" Rules

Although there are typically two parties to a transaction, proposed CFTC Rule 1.3(xxx)(6) turns a transaction into a swap if even one party were trying to circumvent DFA. As stated by CFTC: "[a]lthough deceitful, deceptive, or illegitimate conduct may be sufficient to find that evasion has occurred, such conduct is not a prerequisite for a finding of evasion"[134] and "any attempt to . . . provide a bright-line test of evasion by rule, would likely not be effective as would-be evaders could simply restructure their transactions or entities to fall outside any rigid boundary."[135]

3. CFTC and FERC

CFTC and FERC have neither completed, nor in any report discussed, the Memorandum of Understanding concerning the jurisdictional overlap that was required by DFA Section 720 to have been completed by them within six months after DFA's passage. Instead, CFTC is "not addressing [financial transmission rights] or other transactions in RTOs or ISOs[;]. . . . [P]ersons with concerns about whether FERC-regulated products may be considered swaps (or futures) should request an exemption pursuant to section 722 of the Dodd Frank Act."[136]

4. Environmental Commodities.

The January 18, 2011 *Report on the Oversight of Existing and Prospective Carbon Markets* of the Interagency Working Group, established under section 750 of DFA, concluded that carbon allowances were not within the authority granted to CFTC under DFA,[137] and were therefore not swaps. Nevertheless, in its Adaptation NOPR,[138] CFTC asked if it should change the definition of the word "physical" in its current regulation to a "common sense" meaning, in order to capture environmental commodities within its regulatory purview.[139] If environmental commodities were deemed "swaps," CFTC could pre-empt the regulatory schemes and environmental policies of the EPA as well as state environmental and energy regulators, potentially adding substantial capital costs to renewable resource development.[140] CFTC staff members have been in constructive dialogue with representatives of the EPA.

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[133] *Id.* at 29,829-30.
[134] *Id.* at 29,867, n.326.
[135] *Id.* at 29,866.
[136] *Id.* at 29,839.
[137] *See* INTERAGENCY WORKING GROUP FOR THE STUDY ON OVERSIGHT OF CARBON MARKETS, REPORT ON THE OVERSIGHT OF EXISTING AND PROSPECTIVE CARBON MARKETS at 43, 53 (Jan. 18, 2011), *available at* http://www.cftc.gov/ucm/groups/public/@swaps/documents/file/dfstudy_carbon_011811.pdf.
[138] 76 Fed. Reg. 33,066 (June 7, 2011).
[139] *Id.* at 33,069. The CFTC asks a similar question in its Swap Definition NOPR. *See* 76 Fed. Reg. 29,867 (May 23, 2011).
[140] For example, the developer of a 20-year 100MW wind power purchase agreement with a 30% capacity factor priced at $35 would be required to post $78,840,000 in margin if

5. ISDA lawsuit.

The first judicial challenge to CFTC DFA rulemaking was filed jointly by the International Swaps and Derivatives Association and the Securities Industry and Financial Markets Association to challenge the final rules establishing speculative position limits on certain physical commodity futures and option contracts. The lawsuit follows a challenge "roadmap" laid out by Commissioner O'Malia's dissent, and notes the failure of CFTC to make requisite findings and perform a cost-benefit analysis.[141]

B. Greenhouse Gas Cap and Trade

1. Regional Greenhouse Gas Initiative

On May 26, 2011, New Jersey Governor Chris Christie announced that New Jersey would withdraw from the Regional Greenhouse Gas Initiative (RGGI) by year's end.[142] Governor Christie stated that "after extensive review with the [New Jersey Department of Environmental Protection] and others in my administration, our analysis of [RGGI] reveals that this program is not effective in reducing greenhouse gases and is unlikely to be in the future."[143] On May 31, 2011, the Commissioner of the New Jersey Department of Environmental Protection (DEP) notified the RGGI Executive Director of New Jersey's upcoming withdrawal, effective December 31, 2011.[144] On November 29, 2011, the Commissioner of the DEP notified the other signatories to the RGGI Memorandum of Understanding (MOU) that New Jersey would become a non-signatory to the MOU as of January 1, 2012.[145]

On July 6, 2011, New Hampshire Governor John Lynch vetoed Senate Bill 154,[146] which would have repealed New Hampshire's participation in RGGI.[147] Governor Lynch stated that he was "vetoing this legislation because it will cost our citizens jobs, both now and into the future, hinder our economic recovery, and damage our state's long-

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market prices increased to $50, and the utility would be required to post the same amount if market prices fell to $20. Because intermittent renewable resource projects tend to be "all output" contracts, they could be captured by DFA -- even if environmental commodities are not determined to be "swaps" -- if all-output contracts are "swaps," as discussed above.

[141] *SIFMA and ISDA Petition for Review Filed in the U.S. Court of Appeals for the D.C. Circuit on CFTC's Rule on Position Limits,* SIFMA (Dec. 2, 2011), http://www.sifma.org/issues/item.aspx?id=8589936637.

[142] *See* Press Release, Video and Transcript: Governor Christie: N.J. Future is Green (May 26, 2011), *available at* http://www.nj.gov/governor/news/news/552011/approved/20110526a.html.

[143] *Id.*

[144] Letter from Bob Martin, Comm'r, N.J. Dep't of Envtl. Prot. (DEP), to Jonathan Schrag, Exec. Dir., Reg'l Greenhouse Gas Initiative, Inc. (RGGI) (May 31, 2011), *available at* http://rggi.org/docs/New_Jersey_Letter.pdf.

[145] Letter from Bob Martin, Comm'r, DEP, to RGGI Signatory States (Nov. 29, 2011), *available at* http://rggi.org/docs/Documents/NJ-Statement_112911.pdf.

[146] S. 154-FN, Gen. Court Leg., 164th Sess. (N.H. 2011), *available at* http://www.gencourt.state.nh.us/legislation/2011/SB0154.html.

[147] John H. Lynch, *Governor Lynch's Veto Message Regarding SB 154,* SENATE CALENDAR, Sept. 1, 2011, at 5, *available at* http://www.gencourt.state.nh.us/Senate/calendars_journals/calendars/2011/sc%2036.pdf

term economic competitiveness."[148] On September 7, 2011, the New Hampshire Senate upheld Governor Lynch's veto.

2. California

On July 25, 2011, the California Air Resources Board (CARB) proposed modifications to the Global Warming Solutions Act of 2006 (AB 32)[149] greenhouse gas cap-and-trade program, with a public comment period ending August 11, 2011.[150] On September 12, 2011 ARB proposed additional modifications to the AB 32 cap-and-trade program, with a public comment period ending September 27, 2011.[151] On October 20, 2011, ARB unanimously adopted the final cap-and-trade regulation and Resolution 11-32.[152] On October 27, 2011, ARB filed the final rulemaking package with the California Office of Administrative Law (OAL), and on December 13, 2011 OAL approved the rulemaking and filed the final regulation order with the California Secretary of State, to become effective on January 1, 2012.[153]

The modifications in the final regulation postponed the compliance obligation until January 1, 2013, while maintaining the January 1, 2012 start date for allocation, auction, and trading. The first allowance auctions will be held in August and November 2012. Starting in 2013, auctions will be scheduled on a quarterly basis.[154]

3. Western Climate Initiative and North America 2050

In 2011, Arizona, Montana, New Mexico, Oregon, Washington, and Utah withdrew from the Western Climate Initiative (WCI), which is now composed only of California and the four Canadian provinces of British Columbia, Manitoba, Ontario, and Quebec.[155] The six withdrawing states have joined North America 2050,[156] which was formed by states and provinces currently or previously associated with RGGI, WCI, and the Midwest Greenhouse Gas Reduction Accord (MGGRA).[157] The mission of North America 2050 is to facilitate the "design, promot[ion], and implement[ation] [of] cost-effective policies

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[148] *Id.*

[149] *See Assembly Bill 32: Global Warming Solutions Act*, CAL. AIR RES. BD. (ARB), http://www.arb.ca.gov/cc/ab32/ab32.htm (last visited Feb. 20, 2012).

[150] ARB, Notice of Public Availability of Modified Text and Availability of Additional Documents (July 25, 2011), *available at* http://www.arb.ca.gov/regact/2010/capandtrade10/candt15daynot2.pdf.

[151] ARB, Second Notice of Public Availability of Modified Text and Availability of Additional Documents and Information (Sep. 12, 2011), *available at* http://www.arb.ca.gov/regact/2010/capandtrade10/2nd15daynotice.pdf.

[152] ARB Res. 11-32, California Cap-and-Trade Program (Oct. 20, 2011), *available at* http://www.arb.ca.gov/regact/2010/capandtrade10/res11-32.pdf.

[153] *Cap and Trade 2010: Final Approval*, CARB, http://www.arb.ca.gov/regact/2010/capandtrade10/capandtrade10.htm (last visited Feb. 20, 2012).

[154] *Id.*

[155] *See WCI Provincial and State Partner Contacts*, W. CLIMATE INITIATIVE, http://www.westernclimateinitiative.org/wci-partners (last visited Feb. 20, 2012).

[156] *See* Fact Sheet, North America 2050: A Partnership for Progress at 2, [hereinafter Fact Sheet], http://www.westernclimateinitiative.org/document-archives/general/North-America-2050-Fact-Sheet (last visited Feb. 20, 2012).

[157] In 2010-11, the various signatories to MGGRA stopped pursuing it. *See Midwest Greenhouse Gas Reduction Accord*, CENTER FOR CLIMATE AND ENERGY SOLUTIONS, http://www.c2es.org/what_s_being_done/in_the_states/mggra (last visited Feb. 15, 2012).

that reduce greenhouse gas emissions and create economic opportunities."[158] Unlike RGGI, WCI, and MGGRA, the North America 2050 is not focused on the development and implementation of a greenhouse gas cap-and-trade program.[159]

[158] Fact Sheet, *supra* note 156, at 1.
[159] *See id.* at 2.