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Evolution of U.S. Electric Energy Regulation: From Natural Monopoly Regulation to Regulated Competition

by

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Abstract: Regulation of the interstate wholesale electric energy industry has evolved from cost of service regulation to regulated completion. This article presents an overview of the key means by which the Federal Energy Regulatory Commission brought regulated competition to interstate wholesale electric energy markets by unbundling electric energy generation from electric energy delivery (transmission and distribution) and limiting the opportunities of electric energy providers to exercise market power.

Key Terms: affiliate restrictions; ancillary services; auction revenue rights (ARRs); congestion; day-ahead spot market; demand response; distribution; generation; financial transmission rights(FTRs); locational marginal pricing (LMP); market behavior rules; market manipulation; market monitoring; market power; network integration service; open access same-time information systems (OASIS); open access transmission tariff (OATT); point-to-point service; real-time spot market; regional transmission organizations (RTOS); transmission; unbundling; variable energy resources (VERs); vertically integrated utilities (VIUs)

I. Introduction

The United States electric energy industry has been dominated by vertically integrated utilities (VIUs) regulated on a cost-of-service basis with the goal of insuring that end-users receive non-discriminatory reliable service at just and reasonable rates.¹ From the late 1960s through the mid-1990s, VIUs cost of service skyrocketed because they and their regulators consistently failed to anticipate technological, economic and legal changes.² In response to

¹ David B. Spence, *Can Law Manage Competitive Energy Markets?*, 93 CORNELL L. REV. 765, 767–770 (2008) [hereinafter *Spence*]; Markian M.W. Melnyk & William S. Lamb, *PUHCA's Gone: What Is Next For Holding Companies?*, 27 ENERGY L.J. 1, 7, 11, 12 (2006).

² In the 1960s through the 1970s, many vertically integrated electric energy utilities (VIUs), with the approval of their regulators, constructed large capital-intensive base-load power plants that proved to be uneconomic due to unforeseen cost increases and a slowing of electric energy demand growth. Promoting Wholesale Competition through Open Access Non-Discriminatory Transmission Services by Public Utilities, Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, 60 Fed. Reg. 17,662, 17,668–17,669 (Notice of Proposed Rulemaking, April 7, 1995) [hereinafter OATT's NOPR]; MATTHEW H. BROWN & RICHARD P. SEDANO, A COMPREHENSIVE VIEW OF U.S. ELECTRIC RESTRUCTURING WITH POLICY OPTIONS FOR THE FUTURE, 7-8 (National Council on Electricity Policy; June, 2003), <http://www.ncouncil.org/Documents/restruc.pdf> (last visited June 22, 2013) [hereinafter NCEP OPTIONS]. The

outraged end-users,³ and cost-of-service/Natural Monopoly Theory critics⁴, the federal government through the Federal Energy Regulatory Commission has replaced natural monopoly regulation with regulation competition in interstate electric energy wholesale markets.

Regulated competition advocates believed that competitive electric energy markets could be developed if VIUs' generating facilities were unbundled from their delivery facilities (transmission and distribution) so electric energy vendors and customers could have non-discriminatory access to the VIUs' delivery systems.⁵ Responding to this belief, the Federal Energy Regulatory Commission (FERC) imposed unbundling on wholesale electric energy markets and all interstate transmission not associated with bundled retail sales. VIUs were

unforeseen cost increases were caused by the combined effects of high inflation, high interest rates, two energy price shocks, and the Three Mile Island nuclear power incident. OATTs NOPR, *supra* at 17,669 & n. 47; NCEP OPTIONS, *supra* at 7-8. Electric energy demand growth fell due to a sluggish economy and energy conservation efforts. OATTs NOPR, *supra* at 17,669.

From the late 1970s to the early 1990s, many VIUs entered into long-term contracts to purchase electric energy from new classes of non-utility generators (Qualifying Facilities-QFs, Independent Power Producers-IPPs, and Affiliated Power Producers-APPs) at market-based wholesale prices that proved to be uneconomic due to unforeseen economic, technological, and energy market developments. See OATTs NOPR, *supra* at 17,669-17,671, 17,674; NCEP OPTIONS, *supra* at 8, 10, 11; Charles E. Bayless, *Less Is More: Why Gas Turbines Will Transform Electric Utilities*, PUB. UTIL. FORT. 21 (Dec. 1, 1994).

³ Industrial users first sought and won preferential rates, NCEP OPTIONS, *supra* note 2, at 3, and then they began self-generating and seeking competitive options. OATTs NOPR, *supra* note 2, at 17,669. These strategies reduced the electric energy sales of the VIUs, so rates charged to remaining customers increased to cover the utilities' fixed costs. JEFFREY DASOVICH, WILLIAM MEYER, VIRGINIA A. COE, CALIFORNIA'S ELECTRIC SERVICES INDUSTRY: PERSPECTIVES ON THE PAST, STRATEGIES FOR THE FUTURE 102 (1993), available at [http://www.ucei.berkeley.edu/Restructuring%20Archive/Yellow book.pdf](http://www.ucei.berkeley.edu/Restructuring%20Archive/Yellow%20book.pdf) (last visited June 29, 2013) [hereinafter CALIFORNIA REPORT]. In the early 1990s, the large industrial customers and others began to demand a restructuring of retail and wholesale electric energy markets. *Id.* at 102, 123-133; NCEP OPTIONS, *supra* note 2, at 11, 22.

⁴ See See Harold Demsetz, *Why Regulate Utilities*, 11 J. L. & ECON. 55, 56-65 (1968) [asserting that competitive bid-for-the market mechanisms could effectively replace cost-of-service regulation]; Stephen Breyer, *Analyzing Regulatory Failure: Mismatches, Less Restrictive Alternatives, and Reform*, 92 HARV. L. REV. 552, 562-564 (1979) [documenting market distortions caused by cost-of-service regulation]; Thomas J. DiLorenzo, *The Myth of Natural Monopoly*, Vol. 9, No. 2 THE REVIEW OF AUSTRIAN ECONOMICS 43 44-50, 53, 54 (1996) [asserting that Natural Monopoly Theory was a false doctrine because natural monopolies never existed and that "public utility rate regulation is an anti-consumer monopolistic, price-fixing scheme].

⁵ See, OATTs NOPR, *supra* note 2, at 17,668-17,669; THE ELECTRIC ENERGY MARKET COMPETITION TASK FORCE, REPORT TO CONGRESS ON COMPETITION IN WHOLESALE AND RETAIL MARKETS FOR ELECTRIC ENERGY: PURSUANT TO SECTION 1815 OF THE ENERGY POLICY ACT OF 2005 21-27 (2007), available at <http://www.ferc.gov/legal/fed-ene-pol-act/epact-final-rpt.pdf> [last visited June 29, 2013] [hereinafter COMPETITION REPORT]; NCEP OPTIONS, *supra* note 15, at 22; CALIFORNIA REPORT, *supra* note 3, at 125-125, 188.

functionally unbundled through Open Access Transmission Tariff (OATT) regulation.⁶ Operational unbundling has been achieved in some regions through regulations designed to encourage voluntary formation and effective operation of Independent Systems Operators (ISOs) and Regional Transmission Organizations (RTOs).⁷ Competitive electric energy markets have been fostered through regulations designed to eliminate or mitigate uncompetitive practices.⁸

⁶ Major FERC OATT orders include: Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmission Utilities (Order No. 888), 61 Fed. Reg. 21,540, 21,551-21,552 (April 24, 1996) [hereinafter Order 888]; Open Access Same-Time Information System (Formerly Real-Time Information Networks) and Standards of Conduct (Order No. 889), 61 Fed. Reg. 21,737 (April 24, 1996) [hereinafter Order 889]; Standardization of Generator Interconnection Agreements and Procedures (Order No. 2003), 68 Fed. Reg. 49,846 (July 24, 2003) [hereinafter Order 2003]; Standardization of Small Generator Interconnection Agreements and Procedures (Order No. 2006), 70 Fed. Reg. 34,190 (May 12, 2005) [hereinafter Order 2006]; Interconnection for Wind Energy (Order No. 661), 70 Fed. Reg. 34,993 (June 2, 2005) [hereinafter Order 661]; Promoting Transmission Investment through Pricing Reform (Order No. 679), 71 Fed. Reg. 43,294 (July 20, 2006) [hereinafter Order 679]; Preventing Undue Discrimination and Preference in Transmission Service (Order No. 890), 72 Fed. Reg. 12,266 (Feb. 16, 2007) [hereinafter Order 890]; Standards of Conduct for Transmission Providers (Order No. 717), 73 Fed. Reg. 63,796 (Oct. 16, 2008) [hereinafter Order 717]; Promoting a Competitive Market for Capacity Reassignments (Order No. 739), 75 Fed. Reg. 58,293 (September 20, 2010) [hereinafter Order 739]; Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities (Order No. 1000), 76 Fed. Reg. 49,842 (July 21, 2011) [hereinafter Order 1000]; Integration of Variable Energy Resources (Order No. 764), 77 Fed. Reg. 41,482 (June 22, 2012) [hereinafter Order 764]; Third-Party Provision of Ancillary Services; Accounting and Financial Reporting for New Electric Storage Technologies (Order No. 784), 78 Fed. Reg. 46,178 (July 18, 2013) [hereinafter Order 784].

⁷ Major ISO/RTO orders include: Regional Transmission Organizations (Order No. 2000), 65 Fed. Reg. 809 (Dec. 20, 1999) [hereinafter Order 2000]; Long-Term Firm Transmission Rights in Organized Markets (Order No. 681), 71 Fed. Reg. 43,564 (July 20, 2006) [hereinafter Order 681]; Wholesale Competition in Regions with Organized Electric Markets (Order No. 719), 73 Fed. Reg. 64,100 (Oct. 17, 2008) [hereinafter Order 719]; Demand Response Compensation in Organized Wholesale Energy Markets (Order No. 745), 76 Fed. Reg. 16,658 (March 15, 2011) [hereinafter Order 745]; Frequency Regulation Compensation in the Organized Wholesale Power Markets (Order No. 755), 76 Fed. Reg. 67,260 (Oct 20, 2011) [hereinafter Order 755].

⁸ Major interstate wholesale electric market competition orders include: Order Amending Market-Based Rate Tariffs and Authorizations, 68 Fed. Reg. 65,902 (Nov. 17, 2003) [hereinafter Market Behavior Order]; Prohibition of Energy Market Manipulation (Order No. 670), 71 Fed. Reg. 4244 (Jan. 19, 2006) [hereinafter Order 670]; Conditions for Public Utility Market-Based Rate Authorization Holders (Order No. 674), 71 Fed. Reg. 9695 (Feb. 16, 2006) [hereinafter Order 674]; Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities (Order No. 697), 72 Fed. Reg. 39,904 (June 21, 2007) [hereinafter Order 697]; Order 719, *supra* note 7.

II. Operational Unbundling: Open Access Transmission Tariff (OATT)

The FERC initiated Open Access Transmission Tariff (OATT) regulation by adopting a pro-forma OATT (OATT).⁹ It requires VIUs to (1) “take transmission services (including ancillary services) for all of its new wholesale sales and purchases of energy under the same tariff of general applicability as do others;” (2) “state separate rates for wholesale generation, transmission, and ancillary services;” and (3) “rely on the same electronic information network that its transmission customers rely on to obtain information about its transmission system when buying or selling power.”¹⁰

A. Information Equality

The FERC required transmission providers to provide on an equal basis essential information about the services they offer and the transfer capacity of their transmission systems by developing and using online Open Access Same-Time Information Systems (OASIS) and operating in accordance with mandated Standards of Conduct.¹¹ Subsequently, the FERC ordered transmission providers to improve the calculation and reporting of their available transfer capacity (ATC)—the amount of electric energy that can be moved reliably from one area

⁹ The latest FERC Pro Forma OATT is FERC, PRO FORMA OPEN ACCESS TRANSMISSION TARIFF, available at *Open Access Transmission Tariff (OATT) Reform*, FEDERAL ENERGY REGULATORY COMMISSION, <http://www.ferc.gov/industries/electric/indus-act/oatt-reform.asp> (follow Order No. 890-B Rehearing Order pro forma OATT doc hyperlink), (hereinafter PRO FORMA OATT) [last visited August 2, 2013].

¹⁰ Order 888, *supra* note 6, at 21,552; Order 890, *supra* note 6, at 12,284, 12,285.

¹¹ Order 888, *supra* note 6, at 21,740-21743, 21,748-21,762. Required information includes transfer capability data for each transmission network path of interest, 18 C.F.R. § 37.5(b), transmission services and prices, 18 C.F.R. § 37.5(c), ancillary services and prices, 18 C.F.R. § 37.5(d), data about the nature and ultimate fate of specific transmission and ancillary service requests, 18 C.F.R. § 37.5(e), transmission service schedules, 18 C.F.R. § 37.5(f), other transmission related communications, 18 C.F.R. § 37.5(g), summaries of the time to complete transmission service request studies, 18 C.F.R. § 37.5(h), data concerning the number of transmission service requests that have been granted and denied by path or flowgate, 18 C.F.R. § 37.5(i), and redispatch data. 18 C.F.R. § 37.5(j).

to another on transmission systems after all committed uses are accommodated.¹² The FERC also issued modified Standards of Conduct so that transmission providers must ensure that their transmission operations employees function independently of electric energy marketing employees or those of affiliates, not use conduits to disclose non-public transmission operations information to their own electric marketing employees or those of their affiliates, and operate transparently.¹³

B. OATT Transmission Services

Transmission providers must offer 3 services: firm point-to-point, non-firm point-to-point and network integration.¹⁴ Point-to-point service entitles the transmission customer to receive electric capacity and energy at designated points of receipt and deliver that electric capacity and energy to designated points of delivery.¹⁵ Network integration (network) service entitles network service customers to deliver to their Network Loads (electric energy customers)

¹² The FERC was ordered to work with the North American Electric Reliability Corporation (NERC) and the North American Energy Standards Board (NAESB) to develop “a more coherent and uniform determination of ATC across a region . . .” Order 890, *supra* note 6, at 12,298. This improvement was required because the FERC found potential for undue discrimination from “(1) Variability in the calculation of the components that are used to determine ATC and (2) the lack of a detailed description of the ATC calculation methodology and the underlying assumptions used by the transmission provider.” *Id.* at 12,296.

¹³ In Order 889, the FERC recognized that Standards of Conduct were needed to “to ensure that Transmission Providers do not use their unique access to information unfairly to favor their own merchant functions, or those of their affiliates, in selling electric energy in interstate commerce.” Order 889, *supra* note 6, at 21,743-21,748. The FERC issued the modified code in 2008. Order 717, *supra* note 6, at 63,801-63,816 (Independent Function Rule, now codified at 18 C.F.R. § 358.5), 63,816-63,817 (No Conduit Rule now codified at 18 C.F.R. § 358.6), 63,817-63,922 (Transparency Rule now codified at 18 C.F.R. § 358.7). The Transparency Rule requires transmission providers to post on their websites in a timely fashion information that could be relevant in mitigating or preventing anticompetitive exchanges of information between employees performing transmission functions and employees and affiliate employees engaged in marketing functions . Order 717, *supra*. note 6, at 63,817-63,822.

¹⁴ Order 888, *supra* note 6, at 21,572; Order 890, *supra* note 6, at 12,283, 12,284.

¹⁵ PRO FORMA OATT, *supra* note 9, at §1.37& Part II preamble. Sections relevant to firm point-to-point service include, *id.* at §§ 13.2(iv), 13.5 (entitlement to system expansion), 13.6 (preferred curtailment priority), 13.7(c) (entitlement of firm delivery of capacity and energy). Note, the minimum term of firm point-to-point service is one day, and the maximum term is negotiable. *Id.* at § 13.1. Long-Term firm point-to-point service is for a term \geq 1 year. *Id.* at § 1.19. Sections relevant to non-firm point-to-point service include: §§ 1.28, 14.2, 14.5, 14.7 (low curtailment priority). Note, non-firm point to point service has a minimum term of 1 hour and a maximum term of 1 month, *id.* at § 14.1, but sequential terms can be reserved. *Id.* at §§ 14.1, 18.3.

on a firm basis electric capacity and energy supplied by integrating, dispatching and regulating their Network Resources (generation) in a manner comparable to how a VIU delivers to its wholesale and retail customers (Native Load) electric capacity and energy supplied by its fleet of generators.¹⁶ The OATT details the characteristics of these services and how each is to be initiated and provided.

C. OATT Ancillary Services

The OATT also specifies how seven ancillary services must be provided, including: (1) scheduling, system control and dispatch; (2) reactive supply and voltage control; (3) regulation and frequency response; (4) energy imbalance; (5) spinning reserve; (6) supplemental reserve, and (7) generator imbalance.¹⁷ Transmission providers must insure the provision of the first two

¹⁶ PRO FORMA OATT, *supra* note 9, at §§ 28.1, 28.3, and Part III preamble. Network resources are generating resources owned, purchased or leased by a network customer that are designated for serving its network load under a Network Transmission Service Tariff. *Id.* at § 1.26. Network loads are all loads served by the network customer's network resources. *Id.* at §§ 1.23, 28.1, 31.3. Native Load consists of the wholesale and retail power customers to whom transmission providers are obligated "by statute, franchise, regulatory requirement, or contract" to construct and operate transmission systems to meet their "reliable electric needs." *Id.* at § 1.20.

¹⁷ The first 6 ancillary services were mandated in Order 888, *supra* note 6, at 21,579-21,590. The seventh was added in Order 890, *supra* note 6, at 12,344-12,349. System Control and Dispatch Service "provides for (i) interchange schedule confirmation and implementation with other control areas, including intermediary control areas that are providing transmission service, and (ii) actions to ensure operational security during the interchange transaction." Order 888, *supra* note 6, at 21,581. Reactive Supply and Voltage Support involves the injection or absorption of reactive power to maintain transmission-system voltages within required ranges. BRENDAN KIRBY, ANCILLARY SERVICES: TECHNICAL AND COMMERCIAL INSIGHTS 9 (2007), available at http://www.science.smith.edu/~jcardell/Courses/EGR325/Readings/Ancillary_Services_Kirby.pdf [last visited July 19, 2013] [hereinafter ANCILLARY INSIGHTS]. See Order 888, *supra* note 6, at 21,581-21,582. Regulation and Frequency Response Service involves regulating the balance of energy and load in order to maintain scheduled interconnection frequency at 60 Hz. *Id.* at 21,582. Energy Imbalance Service "makes up for any difference that occurs over a single hour between the scheduled and the actual delivery of energy to a load located within its control area" Order 890, *supra* note 6, at 12,344. Spinning Reserve is the provision of "generating units that are on-line and loaded at less than maximum output [so t]hey are available to serve load immediately in an unexpected contingency, such as an unplanned outage of a generating unit." *Id.* Supplemental Reserve is the capability to serve load in an unexpected contingency by generating units that are on-line but unloaded, by quick-start generation, and by customer-interrupted load, i.e., curtailing load by negotiated agreement with a customer to correct an imbalance between generation and load rather than increasing generation output." *Id.* Generator Imbalance Service makes up for the "differences between energy scheduled for delivery from a generator and the amount of energy actually generated in an hour." *Id.*

ancillary services and must offer to insure the provision of the remaining ancillary services.¹⁸ Transmission customers must acquire the first two ancillary services through their transmission provider, but they may self-supply the remaining ancillary services, or acquire them from their transmission providers or third parties, as long as they are comparable in reliability as the services that the transmission provider would have provided.¹⁹ Ancillary services may be acquired from non-generation sources such as demand response resources owned by electric energy end-users.²⁰

Energy and generator imbalances—the failure of loads and/or electric energy suppliers to take or generate electric energy at pre-scheduled hourly levels²¹—increase the need for many ancillary services.²² To encourage loads and suppliers to stay in balance, the FERC authorized transmission providers to levy imbalance charges.²³ Subsequently, the FERC imposed a standardized three tier imbalance charge schedule to replace the confusingly diverse and often ineffective imbalance charges being levied.²⁴ The FERC has since reduced electric energy

¹⁸ PRO FORMA OATT, *supra* note 9, at § 3.

¹⁹ *Id.*

²⁰ Order 890, *supra* note 6, at 12,378-12,379.

²¹ *Id.* at 12,344.

²² See ANCILLARY INSIGHTS, *supra* note 17, at 1, 7.

²³ Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities (Order No. 888-A), 62 Fed. Reg. 12,274, 12,306-12,307 (March 4, 1997) [hereafter 888-A].

²⁴ Order 890, *supra* note 6, at 12,349, providing narrative descriptions providing data for table below:

Imbalance Charges by Tiers				
			imbalance charge	
	+ bandwidth: the	≥ of	oversched	undersched
Tier	% sched. Energy	MW	% decrem costs	% increm costs
1	1.5	2	100	100
2	1.5 to 7.5	2 to 10	90	110
3	> 7.5	10	75	125

providers' exposure to generator imbalance charges by permitting electric energy providers to change their scheduled generation output at 15 minute intervals.²⁵

The FERC has recently amended the OATT to make it easier for transmission customers or third parties to provide Regulation/Frequency Response (RFR)—achieving the minute-by-minute energy/load balance required to maintain grid frequency at 60 Hz.²⁶ Transmission providers must take into account the speed and accuracy of regulation resources in determining reserve requirements for RFR when determining whether a self-supplying transmission customer has made “alternative comparable arrangements.”²⁷ To help transmission customers and third parties determine whether the resources they would use to provide RFR service meets the comparability standard, transmission providers must post on their OASIS their one-minute and 10-minute Area Control Error (instantaneous difference between electric energy provided and electric energy scheduled) for the last calendar year.²⁸

D. Obtaining Transmission Service

When a prospective transmission customer requests service, the transmission provider must determine on a non-discriminatory basis whether the service can be offered effectively through existing ATC without negatively affecting the electric grid's reliability or the quality and cost of providing service to existing customers.²⁹ If the transmission system's current ATC is

²⁵ Order 764, *supra* note 6, at 41,498-41,499.

²⁶ See definition of Regulation and Frequency Response, *supra* note 17.

²⁷ Order 784, *supra* note 6, at 46,194.

²⁸ *Id.* at 46,195.

²⁹ PRO FORMA OATT, *supra* note 9, at §§ 15.2 (firm point-to-point service), 18.4 (non-firm point-to-point service), 28.2 (network integration service). ATC means the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses, or such definition as contained in Commission-approved Reliability Standards. 18 C.F.R § 37.6(b)(1)(v).

not sufficient, the transmission provider must assess and make available options for overcoming this problem.³⁰ New or upgraded facilities may be required, but the transmission provider temporarily must make available two options to those requesting firm point-to-point service—redispatching (altering the mix and output of generators in ways that could eliminate congestion barriers) and conditional firm service (interrupting service under a limited set of conditions or a limited number of hours to obviate a system constraint)³¹—if they can be offered without negatively affecting electric grid reliability.³²

E. Securing Transmission Capacity

To make existing capacity fully available to prospective transmission customers, the FERC allowed point-to-point transmission customers to reassign all or part of their transfer capacity to others.³³ Originally, the price of reassigned capacity was capped,³⁴ but the FERC removed the cap after noting that the market should keep reassignment prices from rising above the costs of new or upgraded transmission facilities.³⁵

Responding to a Congressional mandate,³⁶ the FERC identified several rate incentives available to jurisdictional transmission providers in conjunction with qualified expansion or upgrading projects, including Return on Equity (ROE) in the upper range of reasonableness, 100% construction work in progress for prudent construction costs, expensing of pre-commercial

³⁰ PRO FORMA OATT, *supra* note 9, at §§ 19.3 (point-to-point service), 32.3 (network integration service).

³¹ Order 890, *supra* note 6, at 12,382 (defining redispatch and conditional firm service).

³² *Id.* at 12,382-12,385, 12,387. PRO FORMA OATT at § 15.4(b).

³³ Order 888, *supra* note 6, at 21,576.

³⁴ *Id.*

³⁵ Order 739, *supra* note 6, at 58,296-58,297.

³⁶ Energy Policy Act of 2005, § 1241, 119 Stat. 961, codified as Federal Power Act, § 219, 16 U.S.C. § 824s(a), (b)(1)-(4), (c), (d).

operations costs, hypothetical rate bases, accelerated depreciation, 100% recovery of prudent costs of constructing plants abandoned for reasons beyond the applicant's control, and deferred recovery of costs delayed by rate freezes.³⁷ These incentives were also made available on a case-by-case basis for those proposing to deploy advanced transmission technologies.³⁸ ROE and accumulated deferred income tax incentives were provided to Trancos, defined as jurisdictional stand-alone transmission companies, regardless of their affiliations with other public utilities.³⁹ ROE incentives are available on a case-by-case basis to utilities joining TOs.⁴⁰

Concerned that future transmission capacity needs were not being planned for efficiently and fairly, the FERC mandated that transmission providers engage in “coordinated, open, and transparent transmission planning on both a local and regional level,”⁴¹ and develop better

³⁷ Order 679, *supra* note 6, at 43,306-43,316.

³⁸ Order 679, *supra* note 6, at 43,326-43,327. Advanced technologies include (1) high-temperature lines; (2) underground cables; (3) advanced conductor technology; (4) high-capacity ceramic electric wire, connectors, and insulators; (5) optimized transmission line configurations (including multiple phased transmission lines); (6) modular equipment; (7) wireless power transmission; (8) ultra high-voltage lines; (9) high-voltage DC technology; (10) flexible AC transmission systems; (11) energy storage devices; (12) controllable load; (13) distributed generation; (14) enhanced power device monitoring; (15) direct system state sensors; (16) fiber optic technologies; (17) power electronics and related software (including real-time monitoring and analytical software); and (18) mobile transformers and mobile substations. 42 U.S.C. § 16422.

³⁹ Order 679, *supra* note 6, at 43,322.

⁴⁰ *Id.* at 43,330.

⁴¹ Order 890, *supra* note 6, at 12,320. The FERC adopted 8 planning principles as guides to what constitutes coordinated, open and transparent planning: (1) Coordination—meeting with stakeholders to develop non-discriminatory transmission plans, *id.* at 12,321, 12,322; (2) Openness—meetings open to all affected parties, *id.* at 12,322, 12,323; (3) Transparency—disclosure of the basic criteria, assumptions and data that underlie [the transmission provider's] transmission system plans,” *id.* at 12,323-12,326 ; (4) Information Exchange—customers submit projections of loads and resources, ” *id.* at 12,326, 12,327; (5) Comparability—plans must meet service requests and treat similarly situated customers comparably, *id.* at 12,327, 12,328 ; (6) Dispute Resolution—dispute resolution mechanisms must be provided, *id.* at 12,328; (7) Regional Participation—transmission planners within interconnected systems must coordinate to share their plans, *id.* at 12,328-12,332; (8) Congestion Studies—at the request of stakeholders, a specified number of meetings must be held annually to address “congestion and/or the integration of new resources (including demand resources) and loads.” *id.* at 12,332-12,335.

project cost allocation methods.⁴² This mandate was later refined to strengthen the regional planning requirement;⁴³ add an interregional planning coordination requirement;⁴⁴ strengthen the cost allocation requirement;⁴⁵ enhance the opportunities for non-incumbent transmission developers to undertake new transmission projects;⁴⁶ and require consideration of transmission and non-transmission options for meeting “reliability requirements, addressing economic issues, and meeting transmission needs driven by public policy”.⁴⁷

⁴² The FERC added a 9th Planning Principle: Cost Allocation—proposals for allocating costs of new projects must “fairly assign[] costs among participants, including those who cause them to be incurred and those who otherwise benefit from them[,] . . . provide[] adequate incentives to construct new transmission[, and . . . be] generally supported by State authorities and participants across the region.” Order 890, *supra* note 6, at 12,335, 12,336.

⁴³ Regional planners must assess whether regional alternatives are superior to local projects and comply with Order 890’s Planning Principles 1-6, & 8. Order 1000, *supra* note 6, at 49, 845, 49,855.

⁴⁴ Interregional Coordinators must assess whether interregional projects could be superior to regional projects. Order 1000, *supra* note 6, at 49, 907, 49,913-49,915.

⁴⁵ Transmission providers were required to develop common regional and interregional cost allocation methods that conformed with 6 allocation principles: (1) Cost Follow Benefits—costs should be allocated to beneficiaries in a manner “roughly commensurate” with benefits received, Order 1000, *supra* note 6, at 49,932, 49,937-49,938; (2) Non-Beneficiaries Don’t Pay, *id.* at 49,939; (3) Benefit/Cost Selection Threshold—benefit/cost thresholds for regional or interregional cost allocation must not exceed 1.25 without FERC assent, *id.* at 49,940-49,941; (4) Geographic Limits—costs of facilities should be allocated solely within the region(s) in which they are located, but effects on other regions and the costs of mitigated them must be assessed, *id.* at 49,941-49,942; (5) Transparency in Identifying Benefits/Beneficiaries—cost allocations and data for determining a project’s benefits and beneficiaries must be documented in a manner that enables stakeholders to understand how they were applied, *id.* at 49,943; (6) Allocation Method Diversity—different cost allocation methods may be used for different types of facilities (e.g., those needed for reliability or congestion relief or meeting public policy requirements). *Id.* at 49,944-49,946.

⁴⁶ The FERC stripped incumbent transmission providers were stripped of their first-right-of-refusal to develop advantage, Order 1000, *supra* note 6, at 49,895, 49,896, and required regional planning participants to (1) establish criteria for determining the eligibility of prospective transmission developers to propose transmission projects, *id.* at 49,897; (2) identify information that must be submitted in support of transmission projects, *id.* at 49,897, 49,898; (3) use transparent non-discriminatory methods of evaluating the merits of proposed transmission projects for purposes of cost allocation, *id.* at 49,898; (4) ensure that projects selected for regional cost allocation are actually eligible for such cost allocation regardless of who sponsors them, *id.* at 49,899; and (5) ensure that all projects are eligible to be considered for regional cost allocation. *Id.*

⁴⁷ Order 1000, *supra* note 6, at 49,868.

F. Securing Generator Interconnection

After OATT regulation began, time-consuming disputes over how to interconnect generators to transmission systems began to undermine wholesale electric energy competition.⁴⁸ In response, the FERC adopted a pro forma large generator interconnection procedures (LGIP) containing a pro forma generation interconnection agreement (LGIA) to standardize how large generators (capacity \geq 20 MW) are interconnected to transmission systems.⁴⁹ The LGIP is designed to ensure that: each interconnection customer is treated fairly;⁵⁰ the desired interconnection service and interconnection points are identified and evaluated to determine their feasibility, their impacts on the transmission system, and facilities that must be added or upgraded to accommodate the service;⁵¹ the parties negotiate agreements specifying how to complete the interconnection;⁵² and required construction is scheduled and rationally

⁴⁸ Order 2003, *supra* note 6, at 49,848.

⁴⁹ *Id.* at 49,847. The latest LGIP is FERC, STANDARD LARGE GENERATOR INTERCONNECTION PROCEDURES (LGIP), available at *Standard Interconnection Agreements & Procedures for Large Generators*, FEDERAL ENERGY REGULATORY COMMISSION, <http://www.ferc.gov/industries/electric/indus-act/gi/stnd-gen.asp> (follow Large Generator Interconnection Procedures (LGIP) hyperlink) [last visited Aug. 6, 2013] (hereinafter LGIP). The latest LGIA is FERC, STANDARD LARGE GENERATOR INTERCONNECTION AGREEMENT (LGIA), available at *Standard Interconnection Agreements & Procedures for Large Generators*, FEDERAL ENERGY REGULATORY COMMISSION, <http://www.ferc.gov/industries/electric/indus-act/gi/stnd-gen.asp> (follow Large Generator Interconnection Agreement (LGIA) hyperlink) [last visited Aug. 6, 2013] (hereinafter LGIA).

⁵⁰ LGIP, *supra* note 49, at 4.1.

⁵¹ *Id.* at §§ 3.2, 3.2.1.1, 3.2.2.1 (describing two types of interconnection service—Energy Resource and Network Resource); § 3.3.4 (describing scoping meetings held to identify and evaluate alternative connection points); § 3.5 (describing process for identifying impacts of project on all affected transmission systems); 6.1-6.4 (describing interconnection feasibility study); 8.1-8.5 (describing interconnection facilities study).

⁵² An optional Engineering & Procurement (E & P) Agreement may be negotiated, LGIP, *supra* note 49, at § 9. The LGIP mandates the negotiation and execution of an LGIA and specifies how to do it. *Id.* at §§ 11.1-11.4.

sequenced.⁵³ The LGIA is designed to specify the parties' rights and obligations with respect to completing the interconnection⁵⁴ and post-interconnection operations.⁵⁵

G. Integrating Unconventional Generators:

The FERC has taken several steps to facilitate the reliable integration of unconventional generators to the nation's electric grid. Finding that small generators (≤ 20 MW) have less revenue earnings potential and are less likely to affect transmission system reliability,⁵⁶ the FERC added to the OATT pro forma Small Generator Interconnection Procedures (SGIP), containing a pro forma Small Generator Interconnection Agreement (SGIA), that impose less burdensome and expensive interconnection requirements than those of the LGIP and LGIA.⁵⁷

⁵³ LGIP, *supra* note 49, at §§ 12.1-12.2.4.

⁵⁴ LGIA, *supra* note 49, at art. 3 (Regulatory Filings), 5 (Interconnection Facilities Engineering, Procurement, & Construction), 6.1 (Pre-Commercial Operation Date Testing and Modifications), 7.1-7.4 (installation of appropriate meters), 8.1-8.2 (installation of communications equipment essential for integrating the operation of the generators with the transmission grid).

⁵⁵ LGIA, *supra* note 49, at art. 9 (Operations), 10 (Maintenance), 11 (Performance Obligation), 12 (Invoice), 13 (Emergencies), 14 (Regulatory Requirements and Governing Law), 15 (Notices), 16 (Force Majeure), 17 (Default), 18 (Indemnity, Consequential Damages and Insurance), 19 (Assignment), 20 (Severability), 21 (Comparability), 22 (Confidentiality), 23 (Environmental Releases), 24 (Information Requirements), 25 (Information Access and Audit Rights), 26 (Subcontractors), 27 (Disputes), 28 (Representations, Warranties, and Covenants), 29 (Joint Operating Committee), and 30 (Miscellaneous).

⁵⁶For reliability, see Order 2006, *supra* note 6, at 34,193 (small wind generator has small impact), 34,198 (size matters in evaluating effects generators have on transmission systems). For small earnings, see *id.* at 34,194, 34,195 (emphasizing that small generators are operated by lots of small businesses), 34,200, 34,201 (need to reduce costs of dispute resolution process so development of small generators will not be discouraged).

⁵⁷ The SGIP and SGIA are simplified versions of the LGIP and LGIA, which include a streamlined default study process for generators with capacities > 2 M, a fast-track process for generators with capacities ≤ 2 MW, and even more simplified reliability screens for small (≤ 10 kW) inverter-based generators. Order 2006, *supra* note 6, at 34,190, 34,194. "An inverter is a device that converts the direct current voltage and current of a DC generator to alternating voltage and current. For example, the output of a solar panel is direct current. The solar panel's output must be converted by an inverter to alternating current before it can be interconnected with a utility's alternating current electric system." *Id.* at 34,190 n. 7. The SGIA provides small generators with reduced insurance obligations and streamlined dispute resolution processes. *Id.* at 34,194-34,195, 34,200-34,201.

The latest SGIP is FERC, SMALL GENERATOR INTERCONNECTION PROCEDURES (SGIP), available at *Standard Interconnection Agreements & Procedures for Small Generators*, FEDERAL ENERGY REGULATORY COMMISSION, <http://www.ferc.gov/industries/electric/indus-act/gi/small-gen.asp> (follow Small Generator Interconnection Procedures (SGIP) hyperlink) [last visited Aug. 6, 2013] (hereinafter SGIP). The latest SGIA is FERC, SMALL GENERATOR INTERCONNECTION AGREEMENT (SGIA), available at *Standard Interconnection Agreements &*

The SGIP and SGIA provide extremely small generators (≤ 2 MW) and even smaller (≤ 10 kW) inverter-based generators (those requiring equipment to convert Direct Current into Alternating Current) with even less onerous requirements.⁵⁸

Large wind-powered generators (≥ 20 MW) do not run at the same speed as synchronous generators, use induction generators, may shutdown during sudden voltage changes, produce electric energy at unpredictably variable rates, and are often unmanned and located in remote areas.⁵⁹ In light of these characteristics, the FERC added appendices to the LGIP and LGIA to require large wind generators to be able to ride out low-voltage events,⁶⁰ and have supervisory control and data acquisition (SCADA) capability of transmitting wind operation data and receiving operating instructions from transmission providers.⁶¹

Generators that produce electric energy at unpredictably variable rates have difficulty producing electric energy in real time equal to their scheduled hourly output, so it is difficult for them to avoid incurring high generator imbalance charges.⁶² To mitigate this problem, the FERC exempted “intermittent” electric energy sources from the third tier imbalance deviation

Procedures for Small Generators, FEDERAL ENERGY REGULATORY COMMISSION, <http://www.ferc.gov/industries/electric/indus-act/gi/small-gen.asp> (follow Small Generator Interconnection Agreement (SGIA) hyperlink) [last visited Aug. 6, 2013] (hereinafter SGIA).

⁵⁸ The fast-track process and the inverter-based process feature, technical screens or a supplemental review to assess whether the generators meet reliability and safety requirements. SGIP, *supra* note 57, at §§ 2.2.1.1-2.2.1.10, 2.4 (Supplemental Review); *Id.* at Attachment 5 (10 kW Inverter Process) § 4.0.

⁵⁹ Order 661, *supra* note 6, at 34,994 & n.4 (non-synchronous), 34,996 (induction generators, grid disturbances, voltage changes), 35,003 (unpredictable electric energy production rates) & n. 31 (unmanned facilities).

⁶⁰ Interconnection for Wind Energy (Order No. 661-A), 70 Fed. Reg. 75,005, 75,008-75,009 (Dec. 12, 2005) [hereinafter Order 661-A]; LGIA, *supra* note 49, at Appendix G: Interconnection Requirements for a Wind Generating Plant, Part A.i, Post-Transition Period LVRT Standard ¶ 1.

⁶¹ Order 661, *supra* note 6, at 35,002-35,004. LGIA, *supra* note 49, at Appendix G: Interconnection Requirements for a Wind Generating Plant, Part A.iii.

⁶² Order 890, *supra* note 6, at 12,349.

band and limited their imbalance charges to those calculated by applying the second tier charges to deviations greater than the larger of 1.5% or 2 MW.⁶³

Variable energy resources (VERs) are electric energy sources that are powered by renewable energy, produce electric energy that cannot be stored, and have variability in output that cannot be controlled by the operator.⁶⁴ To make the integration of VERs more efficient and reliable, the FERC modified the LGIA to require operators of large VERs (≥ 20 MW) to provide site-specific meteorological and forced outage data to transmission providers so they can develop and deploy more accurate power production forecasting methods.⁶⁵ Wind-powered VERs are required at minimum to report data on temperature, wind speed, wind direction, and atmospheric pressure.⁶⁶ Solar-powered VERs are required at minimum to report data on temperature, atmospheric pressure and irradiance.⁶⁷

III. Operational Unbundling: Regional Transmission Organizations (RTOs)

After about 3 years of OATT regulation, the FERC issued rules to encourage the operational unbundling of VIUs through the formation of ISOs/RTOs.⁶⁸ It did so out of concern

⁶³ *Id.*

⁶⁴ Order 674, *supra* note 6, at 41,482 n.1, 41516. Examples include “wind, solar thermal and photovoltaic, and hydrokinetic generating facilities.” *Id.* at 41,482 n.1.

⁶⁵ Order 674, *supra* note 6, at 41,508, 41,110, 41,111.

⁶⁶ *Id.* at 41,509, 41,512.

⁶⁷ *Id.* at 41,509, 41,512.

⁶⁸ Order 2000, *supra* note 7. Currently, there are 7 RTOs/ISOs operating along the lines described *infra* at Operational Unbundling—RTOs through RTO Reforms. Four are multi-state RTOs, including: ISO-New England, <http://www.iso-ne.com/> (operates throughout Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont); PJM, <http://www.pjm.com/home.aspx> (operates throughout Delaware, Maryland, New Jersey, West Virginia and Virginia; in most of Ohio and Pennsylvania; in parts of Illinois, Indiana, and North Carolina; and in fragmentary parts of Kentucky, Michigan and Tennessee); Midwest ISO (MISO), <https://www.misoenergy.org/Pages/Home.aspx> (operates throughout Wisconsin, most of Illinois, Indiana, Iowa, Michigan, Minnesota, and North Dakota; parts of Missouri, Montana, and South Dakota; and fragmentary parts of Arkansas, Kentucky, Ohio, Pennsylvania, and Wyoming); Southwest Power Pool (SPP), <http://www.spp.org/section.asp?pageid=1> (operates throughout Kansas and Oklahoma; most of Nebraska; in parts of

that OATT regulation was insufficient to handle engineering and economic problems emerging from rapid growth in market transactions and increased interconnections among transmission systems.⁶⁹ The FERC was also concerned that VIUs still had incentives to operate their transmission systems in discriminatory ways that may be hard to detect and cannot be prevented without heavy-handed regulation.⁷⁰

To the FERC, effective RTOs have 4 essential characteristics. They are: Independence—being beyond the control of electric energy market participants with respect to how transmission services are provided;⁷¹ Regional Scope—having a regional footprint sufficient for effectively maintaining grid reliability and promoting efficient and fair electric energy markets;⁷² Exclusive Operational Authority—having exclusive control over the operations of all transmission systems within its region;⁷³ Short-term Reliability—having exclusive control over operations essential to maintaining reliability of the integrated grid.⁷⁴

Arkansas, Louisiana, Missouri, New Mexico, and Texas). Three are ISOs operating in the nation's 3 largest states: New York Independent System Operator (NYISO), <http://www.nyiso.com/public/index.jsp>; Electric Reliability Council of Texas (ERCOT), <http://www.ercot.com/>; and California ISO (CAISO), <http://www.caiso.com/Pages/default.aspx>. Information about where these RSOs/ITOs operate can be found at FERC, REGIONAL TRANSMISSION ORGANIZATIONS (RTO)/INDEPENDENT SYSTEM OPERATORS (ISO), <http://www.ferc.gov/industries/electric/indus-act/rto.asp> (last visited Aug. 1, 2013) [hereinafter RTO-ISO]

⁶⁹ Order 2000, *supra* note 7, at 811, 813-815, 823-825.

⁷⁰ *Id.* at 823-825.

⁷¹ *Id.* at 842, 850-859.

⁷² *Id.* at 859-864. In assessing the adequacy of an RTO's boundaries, the FERC said it would consider the whether the boundaries (1) facilitate the performance of essential RTO functions and the achievement of RTO goals, (2), encompass one contiguous geographic area, (3) encompass a highly interconnected portion of the grid, (4) deter the exercise of market power, (5) recognize trading patterns, (6) take into account existing regional boundaries (e.g., NERC regions) to the extent consistent with the Commission's goals for RTOs, (7) encompass existing regional transmission entities, (8) encompass existing control areas, and (9) take into account international boundaries. *Id.* at 863-864.

⁷³ An RTO has sufficient *operational authority* if it has the authority to control the key transmission functions of the transmission facilities under its control and assumes the responsibility for being the security coordinator for its region. Order 2000, *supra* note 7, at 866, 867. Key transmission functions over which the RTO must have operational authority include "switching transmission elements into and out of operation in the transmission system (e.g., transmission lines and transformers), monitoring and controlling real and reactive power flows, monitoring and

The FERC also believe effective RTOs must be capable of performing 8 essential functions. They are: (1) administer its own tariff and employ a transmission pricing system that will promote efficient use and expansion of transmission and generation facilities; (2) create market mechanisms to manage transmission congestion; (3) develop and implement procedures to address parallel path flow issues; (4) serve as a supplier of last resort for all ancillary services required in Order No. 888 and subsequent orders; (5) operate a single OASIS site for all transmission facilities under its control with responsibility for independently calculating TTC and ATC; (6) monitor markets to identify design flaws and market power; (7) plan and coordinate necessary transmission additions and upgrades, and (8) engage in interregional coordination.⁷⁵

A. RTO Ratemaking Guidelines

From its belief that RTOs' success depends on the "feasibility and vitality of the stand-alone transmission business," the FERC issued transmission ratemaking guidelines to insure that RTOs implement efficient and fare pricing of transmission services.⁷⁶ The guidelines call for (1) eliminating pancaked rates so that electric energy transactions with long-distance contract paths will not be burdened by each affected transmission system imposing an access charge;⁷⁷

controlling voltage levels, and scheduling and operating reactive resources.... As security coordinator, the RTO will assume responsibility for: (1) performing load-flow and stability studies to anticipate, identify and address security problems; (2) exchanging security information with local and regional entities; (3) monitoring real-time operating characteristics such as the availability of reserves, actual power flows, interchange schedules, system frequency and generation adequacy; and (4) directing actions to maintain reliability, including firm load shedding." *Id.* at 867.

⁷⁴ This means that the RTO must have exclusive authority over interchange scheduling, redispatching to ensure grid reliability, and transmission maintenance approval. Order 2000, *supra* note 7, at 874, 875.

⁷⁵ Order 2000, *supra* note 7, at 876 (list), 876–877 (discussion of Tariff Administration and Design), 877–888 (discussion of Congestion Management), 888–890 (discussion of Parallel Path Flow), 890–897 (discussion of Ancillary Services), 897–898 (discussion of OASIS, TTC, and ATC), 898–905 (discussion of Market Monitoring), 905–910 (discussion of Planning and Expansion), 910–911 (discussion of Interregional Coordination).

⁷⁶ Order 2000, *supra* note 7, at 913

⁷⁷ *Id.* at 915.

(2) waiving access charges between RTOs to facilitate electric energy transactions with contract paths crossing the borders of two or more RTOs;⁷⁸ (3) flexibly permitting the use of license plate rates so customers pay a single charge to access the entire RTO grid but the rates may differ by location of contract paths so they will enable each affected transmission system to recover its fixed costs;⁷⁹ (4) developing congestion pricing methods, such as locational marginal pricing (LMP) backed by financial transmission rights (FTRs), that ensure least-cost dispatching of generators and allocate limited transfer capacity to those who value it the most;⁸⁰ and (5) encouraging the adoption of a performance based rate (PBR) systems encompassing performance benchmarks, rewards and penalties to create incentives for the RTOs to deliver high quality transmission services.⁸¹

B. RTO Spot Markets

To provide participants with a measure of price and supply certainty, RTOs offer a multi-settlement system comprised of a day-ahead spot market (DAM) and a real-time spot market (RTM).⁸² In the DAM, bids are received on an hour-by-hour basis for supplying and purchasing

⁷⁸ *Id.* at 916.

⁷⁹ *Id.* at 917.

⁸⁰ *Id.* at 887, 917.

⁸¹ Order 2000, *supra* note 7, at 920-922. The FERC issued 5 guidelines for RTOs wishing to file PBR proposals: (1) PBR should not be applied piecemeal; (2) PBR should encompass both rewards and penalties; (3) PBR rewards and penalties should create incentives for an RTO to make efficient operating and investment decisions, and should not compromise system reliability; (4) the benefits of PBR should be shared between the RTO and its customers; To the extent possible, the rewards and penalties should be prescribed in advance based on known and measurable benchmarks. *Id.* at 921-922.

⁸² All the RTOs/ISOs but SPP operate Day-Ahead and Real-Time wholesale electric energy markets. SPP will commence operating both markets on March 1, 2014. See ISO-New England, WHOLESale ELECTRICITy MARKETs-THE MULTI-SETTLEMENT SYSTEM, http://www.iso-ne.com/nwsiss/grid_mkts/how_mkts_wrk/smd_overview/index-p3.html (last visited Aug. 1, 2013); PJM, ENERGY MARKET, <http://www.pjm.com/markets-and-operations/energy.aspx> (last visited Aug. 1, 2013); MISO, DAY-AHEAD, <https://www.misoenergy.org/MarketsOperations/MarketInformation/Pages/DayAhead.aspx> (last visited Aug. 1, 2013); MISO, REAL-TIME AND OPERATING RESERVES MARKET,

electric energy the following day that is not acquired by receivers through bilateral contracts and self-generation.⁸³ These bids determine at each point of receipt and point of delivery within the grid the marginal cost of the last unit of electricity for which there is a willing supplier and a willing buyers (LMPs).⁸⁴ If there is congestion within the grid, the LMPs will be different at many locations to reflect the inability to supply congested locations with electric energy from the lowest-priced generators.⁸⁵ At congested points, the LMP paid by purchasers in the receiving area equals the bid for the last unit supplied by the higher priced generator, but the LMP paid by the generators in preferred sending area equals the bid for the last unit capable of being delivered to the receiving area.⁸⁶ The congestion cost of delivering electric energy equals the difference between the LMP in the receiving area minus the LMP in the sending area.⁸⁷ At the close of the DAM, generators providing bilateral contract supplies and self-generation supplies are cleared for dispatch based on the terms of transmission service contracts and the willingness of the

<https://www.misoenergy.org/MarketsOperations/MarketInformation/Pages/RealTimeMarket.aspx> (last visited Aug. 1, 2013); SPP will offer both Day-Ahead and a Real-Time markets commencing March 1, 2014, SPP, ABOUT THE MARKET PLACE, <http://www.spp.org/section.asp?pageID=143> (last visited Aug. 1, 2013); NYISO, ABOUT NYISO: THE ENERGY MARKETS, http://www.nyiso.com/public/about_nyiso/understanding_the_markets/energy_market/index.jsp (last visited Aug. 1, 2013); ERCOT, DAY-AHEAD MARKET, <http://www.ercot.com/mktinfo/dam/> (last visited Aug. 1, 2013); ERCOT, REAL-TIME MARKET, <http://www.ercot.com/mktinfo/rtm/> (last visited Aug. 1, 2013); CAISO, MARKET PROCESSES, <http://www.caiso.com/market/Pages/MarketProcesses.aspx> (last visited Aug. 1, 2013).

There are variations among these markets. However, they mostly follow the pattern outlined by the FERC in Remediating Undue Discrimination Through Open Access Transmission Service and Standard Electricity Market Design (NOPR), 67 Fed. Reg. 55,542, 55,503 (July 31, 2002) [hereinafter SMD].

⁸³ SMD, *supra* note 82, at 55,489-55,491.

⁸⁴ *Id.* at 55,490, 55,491.

⁸⁵ *Id.* at 55,480, 55,490.

⁸⁶ *Id.* at 55,480.

⁸⁷ *Id.* See also ISO-New England, FTRS AND ARR: WHAT ARE FINANCIAL TRANSMISSION RIGHTS, http://www.iso-ne.com/nwsiss/grid_mkts/how_mkts_wrk/ftsr_arrs/index.html (last visited Aug. 1, 2013) [hereinafter FTRS].

receivers to pay any relevant congestion charges.⁸⁸ Generators supplying those who successfully purchased electric energy in the spot market are also cleared for dispatch.⁸⁹ The relevant LMPs are paid to scheduled spot market suppliers and paid by scheduled spot market purchasers.⁹⁰ Congestion costs are paid by those scheduled to receive electric energy pursuant to bilateral contracts and self-generation.⁹¹

The RTM is an electric energy spot market in which deviations from the quantities of electric energy scheduled to be produced and received in DAM are resolved at real-time LMPs.⁹² Suppliers receive/pay real-time LMP for their over/under production.⁹³ Receivers receive/pay real-time LMP and congestion costs for their under/over receipt of electric energy.⁹⁴

C. Congestion Management:

Most electric energy delivered by RTOs is either purchased by receivers through bilateral transactions or produced by generators owned by VIUs.⁹⁵ For these situations, the price of electric energy is a bilateral contract price or the cost of generation rather than the receiving area LMP,⁹⁶ and the total delivered price of electric energy is the contract price or generation cost

⁸⁸ SMD, *supra* note 82, at 55,487, 55,488

⁸⁹ *Id.*

⁹⁰ *Id.* at 55,491.

⁹¹ See *id.* at 55,481, 55,487, 55,488. However, ISO-New England apparently requires spot market purchasers who pay congested LMPs to also pay congestion costs. See, England, LOCATIONAL MARGINAL PRICING: NODE, http://www.iso-ne.com/nwsiss/grid_mkts/how_mkts_wrk/lmp/index-p2.html (last visited Aug. 1, 2013) [hereinafter LMP-NODE]

⁹² SMD, *supra* note 82, at 55,482, 55,483, 55,492, 55,493.

⁹³ *Id.* at 55,493.

⁹⁴ *Id.*

⁹⁵ *Id.* at 55,483, 55,489.

⁹⁶ *Id.* at 55,480, 55,483 & n. 130.

plus the transmission charge and the congestion charge calculated in the DAM.⁹⁷ For receivers in congested receiving areas who purchased electric energy in the DAM, the total delivered price of electricity is the receiving area LMP plus the transmission charge.⁹⁸

The increased cost in the price of delivered electric energy at congested receiving areas provides market signals that allocate the constricted ATC to suppliers willing to take a price equal to the sending area's LMP and receivers willing to pay the receiving area's LMP price of delivered electric energy.⁹⁹ Thus, LMP insures that electric energy flows on congested pathways do not exceed the constricted ATC by using market signals that allocate constricted ATC to those who value it the most.¹⁰⁰ Over time, these price signals encourage the construction of new transmission capacity to relieve the congestion.¹⁰¹

D. Financial Transmission Rights:

FTRs entitle their holders to receive, or obligate them to pay, a per megawatt share of transmission congestion revenue that is collected hourly on energy flows in one direction within congested areas.¹⁰² They are hedges against the payment of congestion charges when the FTR holder is a receiver of delivered energy in a receiving area with an LMP that higher than the sending area LMP.¹⁰³ Initial allotments were given to existing transmission customers based on

⁹⁷ *Id.* at 55483 & n. 130; LMP-NODE, *supra* note 91.

⁹⁸ SMD, *supra* note 82, at 55,487, 55,488; LMP-NODE, *supra* note 91.

⁹⁹ SMD, *supra* note 82, at 55,480.

¹⁰⁰ *Id.* at 55,480, 55,487 & n. 139, 55,488.

¹⁰¹ ISO-New England, LOCATIONAL MARGINAL PRICING: WHAT ARE THE BENEFITS?, http://www.iso-ne.com/nwsiss/grid_mkts/how_mkts_wrk/lmp/index-p4.html (last visited Aug. 1, 2013).

¹⁰² FTRs, *supra* note 87.

¹⁰³ *Id.*

their historic usage,¹⁰⁴ and FTRs representing the remaining ATC, if any, were made available through auctions to new transmission customers or investors.¹⁰⁵ If new transmission capacity is added to the RTO grid, the aggregate amount of FTRs can be increased by an amount equal to the increase in ATC.¹⁰⁶ Transmission customers who paid the construction costs of the new transmission facilities will be issued FTRs equal to the additional ATC.¹⁰⁷

Revenues collected from the auctioning of FTRs are distributed through Auction Revenue Rights (ARRs).¹⁰⁸ ARR are allocated first to entities that pay for transmission expansions and upgrades that add ATC to the RTO grid.¹⁰⁹ Remaining ARR are allocated to transmission customers who serve electric energy end-users (Load Serving Entities—LSEs) in relation to the amount of load served and where congestion occurs.¹¹⁰

E. Firm Long-term Transmission Rights

Initially, RTOs offered FTRs with maximum terms of only 1 year.¹¹¹ This created congestion cost uncertainty that hampered the financing of large generators and other long-term electric energy supply arrangements.¹¹² So Congress directed the FERC to ensure that LSEs with long-term electric energy supply arrangements could obtain long-term firm transmission

¹⁰⁴ See SMD, *supra* note 84, at 55,484; FTRs, *supra* note 87; Order 681, *supra* note 7, at 43,565.

¹⁰⁵ SMD, *supra* note 84, at 55,484, 55,486, 55,487; FTRs, *supra* note 87.

¹⁰⁶ See SMD, *supra* note 84, at 55,484.

¹⁰⁷ *Id.*

¹⁰⁸ ISO-New England, FTRs AND ARR: AUCTION REVENUE RIGHTS, http://www.iso-ne.com/nwsiss/grid_mkts/how_mkts_wrk/ftrs_arrs/index-p2.html (last visited Aug. 1, 2013) [hereinafter ARR]

¹⁰⁹ *Id.*

¹¹⁰ *Id.*

¹¹¹ See Order 681, *supra* note 7, at 43,566.

¹¹² See *id.*

rights from RTOs.¹¹³ Accordingly, the FERC required RTOs to offer long-term FTRs with a term of at least 10 years,¹¹⁴ establish renewal policies supportive of long-term supply arrangements,¹¹⁵ and support additional ATC to accommodate new long-term transmission rights.¹¹⁶

F. RTO Reforms:

The FERC found that further transparency in long-term electric energy markets would facilitate the formation of long-term electric energy contracts and reduce possible over-reliance on spot markets.¹¹⁷ Accordingly, the FERC required RTOs to establish on their websites a “bulletin board” on which electric energy market participants can post offers to buy and sell electric energy on a long-term basis.¹¹⁸

To make RTOs more responsive to customers and stakeholders, the FERC required them to “establish a means for customers and other stakeholders to have a form of direct access to the board of directors.”¹¹⁹ The FERC also ordered RTOs and ISOs to submit compliance filings that will be assessed in terms of their inclusiveness, fairness in balancing diverse interests,

¹¹³ Energy Policy Act of 2005, § 1233(b), 119 Stat. 960, which required FERC to carry out the mandate of the newly created FPA § 217(b)(4), codified at 16 U.S.C. § 824q(b)(4), to enable “load-serving entities to secure firm transmission rights (or equivalent tradable or financial rights) on a long-term basis for long-term power supply arrangements made, or planned, to [satisfy their service obligations.]”

¹¹⁴ Order 681, *supra* note 7, at 43,575, 43,591, 43,592. The FERC also mandated that firm long-term transmission rights must be firm physically and financially. *Id.* at 43,574, 43,575.

¹¹⁵ Order 681, *supra* note 7, at 43,588, 43,591, 43,592.

¹¹⁶ To this end, the FERC required transmission providers to adopt planning and expansion practices that will take into account the transmission providers’ obligation to provide long-term transmission rights that are firm physically and financially. Order 681, *supra* note 7, at 43,612, 43,613.

¹¹⁷ Order 719, *supra* note 7, at 64,133, 63,134.

¹¹⁸ *Id.* at 64,136, 64,137.

¹¹⁹ *Id.* at 64,154.

representation of minority positions, and ongoing responsiveness.¹²⁰ RTOs were further required to publish their mission statements and/or charters on their websites,¹²¹ and encouraged to make stakeholder/customer responsiveness a factor in setting RTO executive compensation.¹²²

Demand resources—the ability of electric energy end-users to reduce or curtail their consumption in response to economic incentives¹²³—were encountering barriers to providing balancing services by participating in RTO spot markets.¹²⁴ So, the FERC issued mandates requiring the RTOs to treat demand response resources in ways comparable to their treatment of energy supply resources.¹²⁵ Later, the FERC ordered RTOs to pay demand resources on the same basis they pay generators—the market price for energy (LMP)—if they have the capability to balance supply and demand as an alternative to a generation resource and their dispatch will not cause electric energy purchasers’ bills to go up.¹²⁶

The FERC also found that some RTO methods for compensating providers of frequency regulation (FR)—injecting or withdrawing electric energy to keep system frequency at 60 Hz—

¹²⁰ *Id.* at 64,157.

¹²¹ *Id.* at 64,162.

¹²² *Id.*

¹²³ See Order 719, *supra* note 7, at 64,103 & n. 14.

¹²⁴ *Id.* at 64,103.

¹²⁵ *Id.* at 64,104, 64,107. However, comparable treatment extends only to demand resources that “(1) are technically capable of providing the ancillary service and meet the necessary technical requirements; and (2) submit a bid under the generally-applicable bidding rules at or below the market-clearing price” *Id.* To ensure that demand response is treated comparably, RTOs were required “to allow demand response resources to specify limits on the duration, frequency, and amount of their service in their bids,” *id.* at 64,110; exempt buyers from imbalance charges if they took less electric energy in a real-time market period than they scheduled in the day-ahead market in response to RTO calls for help in meeting operating reserves shortages, *id.* at 64,114 ; and allow aggregators of retail customers (ARCs) to enter demand response bids on behalf of their customers if the ARC bids meet the same requirements as others, are verifiable, and do not run afoul of legal prohibitions. *Id.* at 64,119, 64,120.

¹²⁶ Order 745, *supra* note 7, at 16,666-16,669.

were discriminatory and inefficient.¹²⁷ As a consequence, the FERC required RTOs to select PR providers through a bid-based spot market involving a 2-part market clearing price that pays for PR capacity based on the PR providers' cross-product and inter-temporal opportunity costs and PR performance based on response speed and accuracy and the amount service provided.¹²⁸

IV. Controlling Electric Energy Market Power

Market power is the power to raise electric energy prices above the competitive level.¹²⁹ Therefore, the FERC subjects electric energy providers (sellers) to market mitigation and will not allow them to seek or bid market based rates (MBR) if they have market power in horizontal or vertical markets,¹³⁰ violate affiliation restrictions,¹³¹ or violate market behavior rules.¹³² Market mitigation is also used in times of grid disruptions that create electric energy supply shortages.¹³³

A. Market Mitigation

Market mitigation price constraints are imposed on electric energy providers (sellers) found to have horizontal market power.¹³⁴ Such sellers may accept default mitigation or propose mitigation more tailored to their circumstances.¹³⁵ Default mitigation prices are the incremental

¹²⁷ This was because resources are compensated at the same level even when providing different amounts of frequency regulation service. Order 755, *supra* note 7, at 67,268.

¹²⁸ Order 755, *supra* note 7, at 67,270, 67,272, 67,273 (capacity part); 67,273, 67,276, 67,278, 67,279 (performance part).

¹²⁹ SMD, *supra* note 82, at 55,542, 55,503.

¹³⁰ Order 697, *supra* note 8, at 39,907-39,909.

¹³¹ *Id.* at 39,908.

¹³² Market Behavior Order-Appendix A, *supra* note 8, at 65,923, 65,924; Order 674, *supra* note 8, at 9695-9697.

¹³³ Order 719, *supra* note 7, at 64,124, 64,125.

¹³⁴ 18 C.F.R. § 35.38(a).

¹³⁵ *Id.*

cost plus 10 percent for sales no more than one week, an embedded “up to” rate reflecting the costs of the unit(s) expected to provide service for sales greater than one week but less than one year, and an embedded cost rate for sales over one year.¹³⁶

After reviewing supply shortage mitigation practices, the FERC ordered RTOs to reform them out of concern that price or bid caps were not accurately reflecting the true value of energy in times of shortage.¹³⁷ The FERC offered 4 reform approaches, including: (1) increasing energy supply and demand bid caps only during emergencies; (2) increasing only demand bid caps during times of emergencies; (3) establishing a demand curve for operating reserves that would raise bid prices in a previously agreed-to way in the facing of declining reserves; and (4) setting market clearing prices during emergencies for all dispatched supply and demand resources equal to payments made to participants in an emergency demand response program.¹³⁸

B. Horizontal Market Power

Sellers are deemed to have market power in wholesale electric energy markets (Horizontal Market Power) if they have dominant market positions or are pivotal suppliers.¹³⁹ A seller has a dominant market position if its share is $\geq 20\%$ as measured by the MW of uncommitted capacity owned or controlled by the seller as compared to the total uncommitted

¹³⁶ 18 C.F.R. § 35.38(b)(1)-(3).

¹³⁷ Order 719, *supra* note 7, at 64,124.

¹³⁸ *Id.* at 64,126, 64,129. The FERC also established criteria for assessing the merits of shortage pricing rules, including whether they: (1) “Improve reliability by reducing demand and increasing generation during periods of operating reserve shortage;” (2) “Make it more worthwhile for customers to invest in demand response technologies;” (3) “Encourage existing generation and demand resources to continue to be relied upon during an operating reserve shortage;” (4) “Encourage entry of new generation and demand resources;” (5) “Ensure that the principle of comparability in treatment of and compensation to all resources is not discarded during periods of operating reserve shortage;” and (6) “Ensure market power is mitigated and gaming behavior is deterred during periods of operating reserve shortages including, but not limited to, showing how demand resources discipline bidding behavior to competitive levels.” *Id.* at 64,130, 64,131.

¹³⁹ Order 697, *supra* note 8, at 39,909, 39,912, 39,913; 18 C.F.R. § 35.37(c)(1).

capacity in the relevant market.¹⁴⁰ A seller is a pivotal supplier if at the time of annual peak for the balancing authority area “demand cannot be met without some contribution . . . by the seller or its affiliates.”¹⁴¹ If the seller fails either of the foregoing tests, it may demonstrate that it lacks market power through a delivered price test (DPT).¹⁴² DPT more robustly determines the seller’s market share and whether it is a pivotal supplier and uses a market concentration factor (based on the Herfindahl-Hirschman Index HHI = sum of the squares of each seller’s market share).¹⁴³ Under the DPT, the seller lacks market power if it is not a pivotal supplier, and has a market share < 20% in a market with an HHI < 2500.¹⁴⁴

C. Vertical Market Power.

Vertical market power involves using control over transmission or other critical resources to gain advantage in electric energy markets.¹⁴⁵ Operating transmission facilities under an OATT mitigates transmission market power.¹⁴⁶ The FERC monitors sellers’ ownership or control over intrastate natural gas transportation, intrastate natural gas storage or distribution facilities, sites for generation capacity development, and sources of coal supplies and the transportation of coal supplies such as barges and rail cars.¹⁴⁷

¹⁴⁰ Order 697, *supra* note 8, at 39,909, 39,916.

¹⁴¹ *Id.* at 39,909.

¹⁴² Order 697, *supra* note 8, at 39,917, 39,918; 18 C.F.R. § 35.37(c)(3).

¹⁴³ Order 697, *supra* note 8, at 39,918.

¹⁴⁴ *Id.*

¹⁴⁵ *Id.* at 39,908.

¹⁴⁶ *Id.* at 39,953; 18 C.F.R. § 35.37(d). However, violation of OATT requirements can result in a denial or revocation of the right to charge market based rates. Order 697, *supra* note 8, at 39,954-39,957.

¹⁴⁷ Order 697, *supra* note 8, at 39,958; 18 C.F.R. § 35.37(e)(1)-(4).

D. Affiliate Restrictions

Franchised utilities with captive customers and its electric energy sales affiliates must abide by affiliate restrictions regulation in order to seek MBR.¹⁴⁸ Utilities and their affiliates must function separately except in times of emergency,¹⁴⁹ and refrain from sharing market information that could harm captive customers,¹⁵⁰ making preferential sales of non-power goods or services to one another,¹⁵¹ offering preferential power brokering services to one another,¹⁵² and using a conduit as a means of circumventing the affiliate restrictions.¹⁵³

E. Preventing Market Manipulation

The most egregious forms of market manipulation include: Wash Trading—“pre-arranged offsetting trades of the same product among the same parties . . . that involve no economic risk, and no net change in beneficial ownership;” Physical Withholding—falsely declaring that a facility has been forced out of service; Economic Withholding—deliberately submitting high bids in excess of applicable caps and the likely market clearing price; Availability Misinformation—failing to create and report a proper outage schedule and to give immediate notice of any capacity or resource changes that could affect dispatching; Inaccurate/Misleading Reporting—giving false and misleading data to industry publications and market monitors; Dysfunctional Resource Bidding/Scheduling—bidding or scheduling resources

¹⁴⁸ Order 697, *supra* note 8, at 39,960.

¹⁴⁹ 18 C.F.R. § 35.39(a), (c)(1)(2)(i)-(iii).

¹⁵⁰ 18 C.F.R. § 35.39(a), (d)(1), (2).

¹⁵¹ 18 C.F.R. § 35.39(a), (e)(1), (2).

¹⁵² 18 C.F.R. § 35.39(a), (f)(1)(i)-(iii), (2)(i)-(iii).

¹⁵³ 18 C.F.R. § 35.39(a), (g).

that are not physically capable of supplying the needed services.¹⁵⁴ The FERC responded to these activities by promulgated market manipulation rules,¹⁵⁵ and market behavior rules.¹⁵⁶ It

¹⁵⁴ Market Behavior Order, *supra* note 8, at 65,907, 65,908 (wash trading); SMD, *supra* note 84, at 55,509, 55,510 (the rest).

¹⁵⁵ The market manipulation rules prohibit any entity engaged in the purchase or sale of electric energy or transmission service (1) To use or employ any device, scheme, or artifice to defraud, (2) to make any untrue statement of a material fact or to omit to state a material fact necessary in order to make the statements made, in the light of the circumstances under which they were made, not misleading, or (3) to engage in any act, practice, or course of business that operates or would operate as a fraud or deceit upon any entity. 18 C.F.R. § 1c.2(a)(1)-(3). These rules were adopted in Order 670, *supra* note 8, at 4258, in response to response to new a new Congressional mandate to promulgate rules making it unlawful to use any manipulative or deceptive device or contrivance in conjunction with the purchase/sale of electric energy or transmission services. Energy Policy Act of 2005, § 1283, now codified at 16 U.S.C. § 824v.

¹⁵⁶ (a) Unit operation. Where a Seller participates in a Commission-approved organized market, Seller must operate and schedule generating facilities, undertake maintenance, declare outages, and commit or otherwise bid supply in a manner that complies with the Commission -approved rules and regulations of the applicable market. A Seller is not required to bid or supply electric energy or other electricity products unless such requirement is a part of a separate Commission-approved tariff or is a requirement applicable to Seller through Seller's participation in a Commission-approved organized market.

(b) Communications. A Seller must provide accurate and factual information and not submit false or misleading information, or omit material information, in any communication with the Commission, Commission-approved market monitors, Commission-approved regional transmission organizations, Commission-approved independent system operators, or jurisdictional transmission providers, unless Seller exercises due diligence to prevent such occurrences.

(c) Price reporting. To the extent a Seller engages in reporting of transactions to publishers of electric or natural gas price indices, Seller must provide accurate and factual information, and not knowingly submit false or misleading information or omit material information to any such publisher, by reporting its transactions in a manner consistent with the procedures set forth in the Policy Statement on Natural Gas and Electric Price Indices, issued by the Commission in Docket No. PL03-3-000, and any clarifications thereto. Seller must identify as part of its Electric Quarterly Report filing requirement in § 35.10b of this chapter the publishers of electricity and natural gas indices to which it reports its transactions. In addition, Seller must adhere to any other standards and requirements for price reporting as the Commission may order.

(d) Records retention. A Seller must retain, for a period of five years, all data and information upon which it billed the prices it charged for the electric energy or electric energy products it sold pursuant to Seller's market-based rate tariff, and the prices it reported for use in price indices.

18 C.F.R. § 35.41(a)-(d).

Originally, the FERC adopted 6 Market Behavior Rules that were designed to prevent practices that caused extreme disturbances in the Western markets in 2001-2002. Market Behavior Order, *supra* note 8, at 65,902. After the adoption of the Market Manipulation Rules, the FERC eliminated 2 of the original 6 Market Behavior Rules and codified the remaining 4 as shown above. Order 674, *supra*. note 8, at 9,695-9,697.

18 C.F.R. § 35.41(a)-(d).

also required RTOs to establish market monitoring units (MMUs) and give them the independence, authority and investigatory tools required to perform their functions.¹⁵⁷

V. Concluding Observations

Several conclusions can be drawn from this survey of how U.S. electric energy regulation evolved from natural monopoly regulation to regulated competition. First, regulated competition is more complex than natural monopoly regulation, and imposes more technically difficult tasks and transaction costs on the regulated community. Second, the principle goal of regulated competition seems to be putting resources in the hands of those willing and able to pay the most for them in the belief that reliable service at just and reasonable prices will be the natural byproducts. Third, it is debatable how much true support there is for regulated competition among end-users, state officials and other stakeholders, for to date RTOs do not operate in all or parts of 28 states located in the South, the Plains and the West,¹⁵⁸ and only 15 states have implemented actively the retail choice version of it.¹⁵⁹

¹⁵⁷ Order 719, *supra* note 7, at 64,139. To enhance their independence, MMUs report to the RTO board instead of to its management. *Id.* at 64,140. MMU personnel may not have any financial or professional interests in electric energy market participants. *Id.* at 64,144-64,145. MMUs core tasks include evaluating “market rules, tariff provisions and market design elements;” reviewing and reporting on electric energy market performance; and identifying and reporting the behavior of market participants that warrants an investigation. *Id.* at 64,141. MMUs must also issue state-of-the-market reports quarterly and annually. *Id.* at 64,148.

¹⁵⁸ RTOs do not operate at all 12 states, including: Alabama, Arizona, Colorado, Florida, Georgia, Idaho, Mississippi, Nevada, Oregon, South Carolina, Utah and Washington. RTOs do not operate in most of 9 states, including: Arkansas, Kentucky, Louisiana, Montana, New Mexico, North Carolina, South Dakota, Tennessee, and Wyoming. RTOs do not operate in parts of 3 states, including California, Iowa and Missouri. RTOs do not operate in fragmentary parts of 4 states, including: Minnesota, Nebraska, North Dakota, and Texas. See RTO-ISO, *supra* note 68.

¹⁵⁹ These states include: Connecticut, Delaware, Illinois, Maine, Maryland, Massachusetts, Michigan, New Hampshire, New Jersey, New York, Ohio, Oregon, Pennsylvania, Rhode Island and Texas. Washington, D.C. has also adopted Retail Choice. United States Energy Information Administration, Status of Electricity Restructuring by State, http://www.eia.gov/electricity/policies/restructuring/restructure_elect.html (last visited Aug. 1, 2013).