International Experience with Private Sector Participation and Open Access in Power Grids

Open Access Component

Global Review

Report

Ashley C. Brown,

Executive Director, Harvard Electricity Policy Group, Kennedy School of Government, Harvard University

Of Counsel, Greenberg Traurig

In Collaboration with Raya Salter, Environmental Defense Fund

Table of Contents

1. North America

(a) The United States

(i) Competition and the Development of the U.S. Electricity Sector

Competition in U.S. electricity markets dates back to the very beginning of the industry's late 19th and early 20th century origins.[1] The central station model, where electricity was generated and then distributed within geographic territories defined by municipalities or other non-national, regulatory authorities, became prevalent. Multiple systems evolved, often in close proximity to each other.[2] This led to new forms of competition with many companies bidding for municipal franchises (a.k.a. concessions or licenses) and often expanded to include areas surrounding municipalities. Each franchisee was obligated to provide full service to all consumers within the territory they were assigned, but were also generally afforded monopoly status in exchange for accepting the obligation of providing universal service. Another tradeoff for monopoly status, of course, was that prices were fully regulated so that the extraction of monopoly rentss was precluded. Thus while competition to serve individual customers was not permitted, other forms of competition, such as bidding for franchises, was permitted, although it sometimes included some negative aspects (e.g., franchises obtained by corrupt means). In addition, the regulatory oversight of franchisees was often carried out on an unprofessional and frequently corrupt basis. Those circumstances led to the emergence of an unusual coalition that gave birth to a regulatory regime at the state (i.e., not national) level that has continued in basically the same form for the last 100 + years, albeit with a substantial role for federal

[1] For an expanded discussion, see Smart Grid and Competition: A Policy Paper Prepared by Ashley Brown, Steven Levitsky and Raya Salter for the Galvin Initiative, 2011, available at: ("Competition Policy Paper").

[2] Report to Congress on Competition in Wholesale and Retail Markets for Electricity Energy Pursuant to Section 1815 of the Energy Policy Act of 2005, The Electric Energy Market Competition Task Force, 2007 ("EPACT 2005 Report to Congress") at p. 17. Between 1887 and 1893, there were 24 central station power companies in the city of Chicago alone. Steven Stoft, "Power System Economics, Designing Markets for Electricity," *IEEE Press 2002* ("Power System Economics") at p. 6. *See also* the Competition Policy Paper.

regulation inserted into it with some preemptive effect. Utility magnates, including the most prominent of them, Samuel Insull, believed regulation would be nominal and subject to substantial industry influence. Insull came to view regulation as a way to sustain a monopoly market position that the public might not otherwise tolerate. Progressives, in contrast, not generally predisposed to favor monopolies, saw professional, competent regulation at the state level as an effective means of controlling market power as well as an antidote to the corruption that characterized the creation and control of municipal franchises.

With this diverse base of support for establishing regulation, in 1907, New York and Wisconsin became the first states to give electricity jurisdiction to public utility commissions,[3] an action that was ultimately followed by every state, the last of which was Texas in 1975.

The industry largely emerged on a state by state basis, often loosely interconnected, if connected at all, but always vertically integrated, with geographically constrained markets. This meant that many of the characteristics typically found in other markets were not present in electricity.[4] Electricity is perhaps the most capital intense industry in the world with high fixed costs for investments in generation, transmission and distribution networks.[5] That investment carried substantial risk. Long-term financing structures, and long-term revenue streams to sustain them, were seen as essential to accommodate the large investments and to provide investors with assurances that the risks were reasonable.[6]

[3] By 1916, 33 states had granted jurisdiction to state commissions or agencies to regulate electric utilities. *See* EPACT 2005 Report to Congress at p. 44. Most, although not all, state public utility regulatory agencies pre-existed the emergence of the electricity industry, as they had been created to regulate other such infrastructure industries as railroads, water and sewers, and canals. Thus, for many, although not all states, the authority to regulate electricity was simply the expansion of the powers of agencies that already existed, rather than the creation of a new function entirely. These agencies also typically acquired powers to regulate natural gas, buses and trucks, and telecommunications, as well. *See also* the Competition Policy Paper.

[4] It is important to note, however, that many of the reasons electricity markets were different did not necessarily result from "natural" factors, but were the result of legal, political, and, in some cases, technological constraints.

[5] The EPACT 2005 Report to Congress at p. 17. *See also* the Competition Policy Paper.

[6] *Id.*

An element of assuring financial sustainability, as well as of controlling costs that would be passed on to customers, was the attainment of economies of scale in generation, transmission and distribution.[7] The attainment of those economies of scale as well as technological advances, not only provided comfort to investors but also led to an industry with declining costs. This allowed for regulatory certainty and provided little economic or legal space for new entrants to take on "entrenched" monopolies.

It is important to note, however, that the monopoly was never absolute. Distributed generation, including co-generation, for example, remained. The aftermath of the Great Depression of the 1930s and the New Deal (the administration of President Franklin Roosevelt) designed to address it brought new elements of competition. This included the creation of rural electric cooperatives to provide electricity to unserved rural areas[8] by creating huge federal hydro stations and entities such as the Tennessee Valley and Bonneville Power Authorities. In addition, federal power marketing authorities, such as the Southwest Power Authority, were created and given preferential access to public power entities (i.e., electric utilities owned by municipal governments, public entities created by state governments, or by consumer owned cooperatives) for access to low-cost hydro facilities.[9]

Many states also strengthened public power entities within their territories to better enable competition, at least on the margin.[10] Larger industrial customers with multiple centers of

---

[7] *Id.*

[8] Many investor owned utilities, which focused on providing service in high density urban/suburban areas or along the rights of way of electric railroads, had been reluctant to provide service to sparsely populated, usually higher cost, rural areas, and resisted efforts to compel them to do so. That resistance was particularly strong where rural areas were also characterized by high concentrations of poverty or other unattractive load characteristics.

[9] The New Deal also brought with it a substantial tightening of federal utility regulation in the form of the passage of the Public Utility Holding Company Act, a measure deemed necessary by Congress to plug "loopholes," state regulatory schemes and limits to state jurisdictional boundaries. *See also* the Competition Policy Paper.

[10] The states within the TVA and BPA footprints were particularly active, but so were such states outside those footprints as Nebraska and New York. Indeed, Franklin Roosevelt, then Governor of New York, in his 1932 campaign for President described public power as the "birch rod in the cupboard," which the citizenry could use to

production could shift their production from a jurisdiction with high electricity prices to another with lower prices in order to pressure higher cost utilities to provide lower priced electricity. In many cases, over time, this led to the replacement of industrial tariffs by individual service contracts. These contracts reflected not the costs of service, but rather the price required to avoid the loss of load. Utilities themselves, with different cost structures and varied operating efficiencies, developed their own forms of benchmark competition among themselves. Even where they did not use them, politicians and consumer groups often brought pressure on higher priced companies by comparing the prices and cost structures of the various utilities.

Those price differentials were made transparent by two factors. Regulators at both state and federal levels imposed public reporting requirements that placed them in transparent *plain view*. Secondly, as the grid became more interconnected and trading opportunities between utilities were enabled, market participants were able to exploit and take commercial advantage of them. Trading was facilitated by the fact that vertically integrated utilities had been building high voltage transmission facilities to link their generation to load centers. As generators got bigger, creating more pollution, the transport costs of fuels from mine to plant grew. Generating facilities had to move away from load centers in populated areas to more distant locations, often closer or more convenient to energy resources. This necessitated the development of high voltage transmission lines. Mergers and co-ownership of assets among utilities also contributed to the need for additional transmission assets. While some of the consolidations led to concerns about the effectiveness of regulation of dispersed assets,[11] the construction of high voltage

---

compete with private power companies that were "gouging" the public or not providing good service. *See also* the Competition Policy Paper.

[11] Electric utility holding companies, with significant multistate operations, and perhaps even unregulated subsidiaries, rose in prominence, and tested the limits of effective regulation by the states. The Public Utility Holding Company Act of 1935 (since repealed) required the interstate utilities to either break up or restructure themselves to fit more fully under the regulatory regimes on the states, or, in the alternative, subject themselves to very restrictive federal regulatory oversight by the Securities and Exchange Commission, which included

networks to serve them, over time, came to be recognized as something more than connections between source and sink, but also as a means of commerce enabling trading in electricity. By the 1980s, policy makers and regulators took notice of the opportunities and became quite serious about developing highly sophisticated means of transmission pricing. This supplanted the old system of simply adding transmission to the asset base of retail utilities and imposing the burden for meeting revenue requirements on the utility's native load customers. These developments, of course, were closely related, indeed, perhaps synergistic, with increased wholesale market trading in electricity.[12]

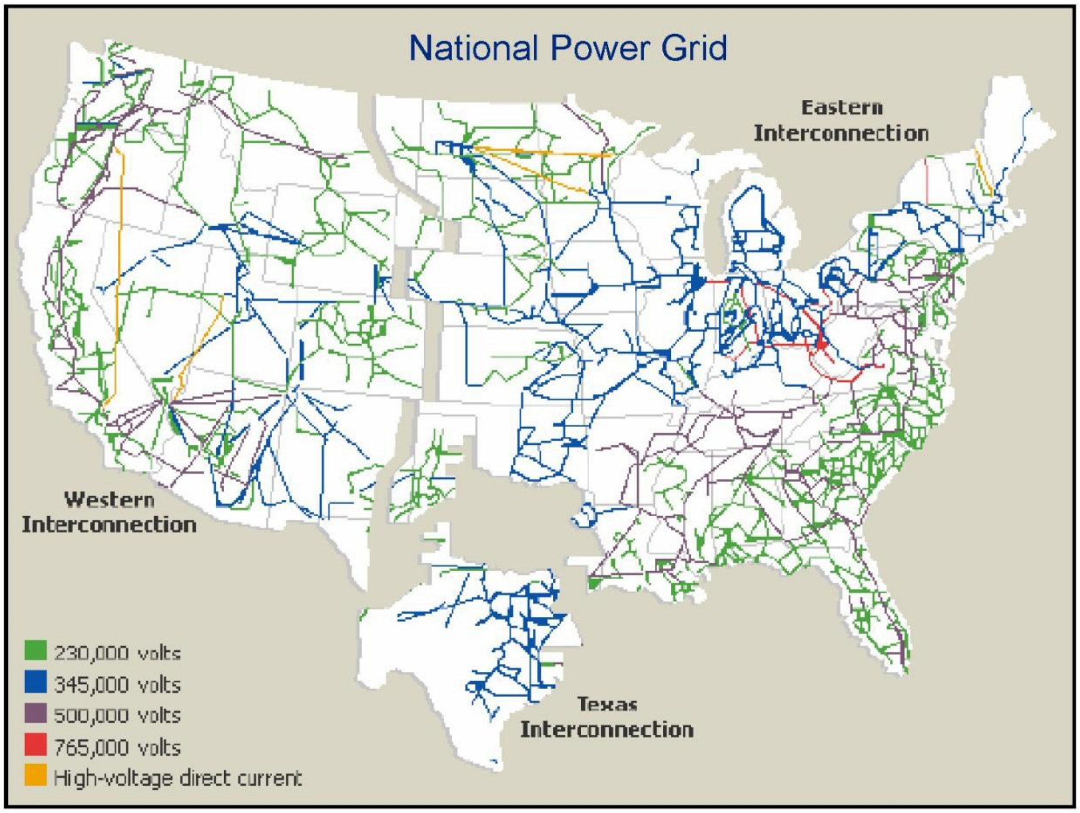
While transmission lines were generally planned to accommodate the needs of vertically integrated companies, both the need for increased reliability and the potential for economies of scale, not to mention opportunity for arbitrage and/or symmetry between neighboring utilities, led to increased opportunity for energy trading. Over time, the trading became a significant characteristic of the industry. Thus, in the context of the growth of regulated monopolies, some forms of competition not only persisted, but, for the most part, actually grew. In electric policy and regulatory forums, as well as in litigation, the question of how to deal with competition issues was never far beneath the surface. Over time, it became perhaps the predominant issue in policy and regulatory forums. The chart below depicts the modern American Power Grid.[13]

---

geographic consolidation of commercial activity. The 2005 repeal of the Act constituted recognition by the Congress of the emergence of a market where competition was supplanting, although not eliminating, regulation as the predominant means of price setting in the bulk power (i.e., wholesale) market. *See also* the Competition Policy Paper.

[12] Wholesale markets were slow to develop, as early interstate transactions were limited and wholesale transactions were primarily long-term contracts by IOUs to sell and deliver to public and cooperative utilities. *See also* the Competition Policy Paper.

[13] Chart extracted from Jon Mostel and Eli Farrah, "Building Out the Grid," Dewey & LeBoeuf, 2009 ("Building Out the Grid").



(b) The Regulation of Open Access

Even before the full policy debates about competition in the power sector became full blown, the historic existence of competition on the margins of the sector had begun expanding through the interventions of the Courts. Two cases stood out. In 1927 the U.S. Supreme Court noted in *North Attleborough* that states lacked jurisdiction over the rates of a transaction between utilities in adjoining states. Such transactions constituted interstate commerce and matters that were solely within the jurisdictional authority of the federal government. Since no federal agency then existed to look after such transactions, a regulatory void existed. Within a few years, the Congress filled the void by creating the Federal Power Commission (it became the Federal Energy Regulatory Commission ("FERC") in 1977.[14] Thus, a formal regulatory agency

[14] *See* the Department of Energy Organization Act of 1977.

to deal with bulk power markets and to focus on wholesale transactions and the movement of bulk power came into existence. In 1973, the Supreme Court decided the case of *Otter Tail Power Co. v. United States.*[15] There, the Court applied the Sherman Act[16] to a utility that had monopoly control over local transmission in regard to their refusal to provide transmission access. In *Otter Tail Power Co.*, Otter Tail, the defendant, was a regulated utility that wielded power over transmission lines it owned and operated. Otter Tail also distributed power under franchises granted by local municipalities. The government, on behalf of the municipalities, charged that Otter Tail tried to prevent towns from establishing their own power systems when Otter Tail's retail franchises expired and refused to transmit or wheel power from other sources on its transmission lines.[17] The Supreme Court held that Otter Tail was in violation of the Sherman Act. It rejected Otter Tail's claims that it was not subject to antitrust regulation because the Federal Power Act preempted antitrust jurisdiction.[18]

The face of policy began to change in more fundamental ways in the shadow of the energy crisis of the 1970s. The Public Utilities Regulatory Policies Act ("PURPA") was passed in order to promote alternative sources of energy (both in terms of the resources used to generate and in terms of non-traditional ownership, namely non-utilities) and to promote energy efficiency. The legislation constituted a major stimulation of competition in the electricity industry. It did so by requiring utilities to purchase energy from "Qualified Facilities" (QF's), which were turbines who used excess steam from industrial steam hosts (co-generators) to generate electricity at their "avoided cost." Aided by gas turbine technology, by favorable

[15] 410 U.S. 366 (1973).
[16] The Sherman Act, 15 USC Sections 1-7, is the US federal statute on competition passed by Congress in 1890, prohibiting certain business activities that reduce completion in the market place like, for example, limiting cartels.
[17] *Id.* at 366.
[18] *Id.*

calculation of "avoided costs" by regulators in a number of states,[19] and by increased costs of utility generation, primarily nuclear, PURPA greatly increased non-utility generation.[20] It enabled the birth of the merchant generator business and opening the door to the eventual entry of independent power producers into the market.[21]

The Energy Policy Act of 1992 ("EPACT of 1992") amended the Federal Power Act ("FPA") to allow generators and other market participants selling or buying electricity for resale to apply to FERC for an order to access utility transmission assets if it refused access.[22] The Act also exempted independent power producers ("IPPs"), both truly independent entities as well as utility affiliates, from the provisions of PUHCA that had, up to that point, largely precluded widespread development of an IPP business model. In 1996, FERC Order No. 888[23] went further and required adherence to nondiscriminatory open access rules and also required that generation and transmission functions be unbundled.[24] It also provided that transmission owners provide all potential transmission users with real time information on availability of transmission capacity to accommodate transactions by third parties.

Even before the passage of the 1992 Act, in the decade of the 1980s, the FERC had begun to change course, moving away from traditional cost-of-service ratemaking at the

---

[19] The variation in calculating "avoided costs" among the states was very wide. While many states calculated those costs at such low levels that they attracted very little QF investment, in other states, however, particularly California and the northeast, the calculation was very favorable to the new entrants. Ultimately, federal regulators stepped in to impose competitive bidding to ascertain "avoided costs" and, thereby, impose more uniformity and market discipline in the method for calculating costs.
[20] Many generators came to be known as "PURPA Machines," because to many observers the steam host, in all too many cases, seemed more contrived than real, in the sense that they were designed more to meet PURPA requirements than for legitimate engineering purposes.
[21] Merchant generators and independent power producers entered the market, producing 9% of U.S. electricity generation by 1991. The full participation of independent generators in the market place required the creation of some exemptions to the requirements of Public Utility Holding Company Act, which did not occur until the Energy Policy Act of 1992. PUHCA itself was repealed in the first decade of the 21st century.
[22] 16 U.S.C. § 8241. *See also* the Energy Antitrust Handbook, ABA Section of Antitrust Law (Second Edition 2009) at p. 30-32.
[23] Order No. 888, Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities, 61 Fed. Reg. 21,540 (May 10, 1996).
[24] *Id. See also* ABA Handbook at p. 4.

wholesale generation level, toward pricing based on the market rather than on costs. Thus, just a year after passage of EPACT of 1992, FERC granted market-based rates to an affiliate of a vertically integrated IOU. It did so, however, only after satisfying itself that the company could not dominate the relevant generation market.[25] The denial of market-based rates for generation by the FERC would place a generator at a major disadvantage in wholesale energy and capacity markets. This is because without such rates they would be unable to sell without submitting themselves to an expensive and time consuming rate case which would necessarily compel them to disclose market sensitive cost. This is a process and examination which their competitors would be able to avoid entirely. Thus, even without explicit statutory authority to do so, the FERC was able to essentially compel open transmission access.

FERC has since approved hundreds of applications for market-based rate authority, and, as set forth in orders 697 and 697-A,[26] requires that public utilities and their affiliates demonstrate either a lack of horizontal and vertical market power or adequate mitigation if it does exist.[27] FERC conditions the granting of this authority on restrictions governing the relations between a regulated power sales affiliate and its public utility affiliate with captive customers.

In the 1980s, in exercising its jurisdiction over wholesale natural gas markets, FERC not only mandated open access on pipelines, but also ordered that companies had to choose between being in the business of selling gas or of transporting it, but could not be in both. By doing so, it eliminated the possibility that control of the pipeline could be used for competitive advantage in

---

[25] Heartland Energy Services 68 FERC 61,223 (1994). *See also* James H. McGrew, "FERC: Federal Energy Regulatory Commission, ABA, 2009" (McGrew).
[26] In Order No. 697, FERC "(1) adopted revised screens for determining whether sellers have horizontal and vertical market power, (2) adopted revised rules to prohibit affiliate abuse, (3) adopted default rules for mitigation for certain classes of sales, (4) did not require a standardized tariff or a blanket "must offer" condition, and (5) committed itself to active review of transactional reports filed by market-based sellers." As quoted from McGrew at p. 197.
[27] FERC website, available at http://www.ferc.gov/industries/electric/gen-info/mbr.asp.

the commodity market. Many observers expected FERC to take similar actions in electricity in order to assure open access. For a variety of legal, tax and political reasons, it did not do so. Rather, it ordered "functional" unbundling in which transmission costs were strictly segregated from other costs, and in which transmission managers were subject to a strict code of behavior. These codes precluded them from providing competitively sensitive information to corporate affiliates in other businesses unless they provided such data to all users on a nondiscriminatory basis. On December 20, 1999, the FERC issued Order No. 2000.In it the Commission went even further, albeit on a voluntary basis,[28] by encouraging the formation of regional transmission organizations ("RTOs") to administer the transmission grid on a regional basis throughout.[29]

While the FERC and Congress were increasingly focused on encouraging competition in the wholesale market, in the 1970s and 1980s, an entirely different focus was developing in retail regulation being carried out in the various states.[30] New theories of regulation beyond traditional rate of return gained prominence as regulators and policymakers contemplated, or faced calls for, reform and/or restructuring.[31] The primary focus in the late 1970s and early 1980s in state regulation was to call for public involvement in and regulatory oversight of electric utility planning. This was largely in reaction to the energy crisis of the 1970s, but also to correct for

[28] The FERC may have contemplated mandating membership in RTOs, but never actually did so. Subsequent Court decisions strongly suggest that the Commission lacks the legal authority to compel a company to join an RTO.
[29] 89 FERC ¶ 61,285 (1999). Order No. 2000 delineated the characteristics and functions that an entity must satisfy in order to become a RTO.
[30] It is critical to understanding electricity regulation in the U.S. to know that federalism is a major factor. Wholesale markets and transmission access and pricing are jurisdictional to the federal government, but retail markets and licensing for generation and transmission are largely a function of regulation at the state level. While regulation at one level influences regulation at the other, neither necessarily binds the other, as long as they confine themselves to the areas where their authority is clear. Where their claimed powers conflict, it is up to the Courts to decide if the federal regulators have the power to preempt their counterparts at the state level, a determination that is very fact and circumstance specific.
[31] Paul L Joskow, *Incentive Regulation in Theory and Practice: Electricity Distribution and Transmission Networks*, August 15, 2007, available at: *www.hks.harvard.edu/hepg/Papers/**Joskow_Incentive**_2006.pdf*

what were widely seen as perverse incentives inherent in rate of return regulation.[32] The objective was to assure the reliability of supply on an efficient, least-cost basis, including not only those on the supply side, but those on the demand side as well.

That process was originally labeled "least cost planning," but more commonly came to be known as, "integrated resource planning" (IRP).[33] As a result of IRP processes, more utilities were encouraged to "buy rather than build" (e.g., from PURPA qualified facilities or neighboring utilities) and were ordered to implement demand-side management programs. While IRP processes did not lead to many pricing reforms in terms of signals provided to end users,[34] one clear by-product of IRP was a broad recognition of the fact that utility incentives that tied revenue to sales provided utilities with a powerful bias to sell more energy. This predisposition directly contradicted the important public policy objective of encouraging more energy efficiency.[35] In short, utility self-interest, which should have been aligned with the public interest in efficiency, was not only unaligned, but, in fact, was directly contrary to it. Addressing that misalignment of interests required, in the view of many state regulators at the time, much stronger regulation than had heretofore existed. This was needed in order to do things that were

[32] Some of these so-called "perverse" incentives were "gold plating" and building "excess capacity" because profits were directly linked to levels of capital investment rather than productivity, hostility to purchasing less expensive capacity or energy rather than what a company could produce itself because purchased power was not allowed to be marked up, and an unwillingness to pursue demand-side options because revenues were tied to sales and demand-side efficiency would reduce sales, and therefore, revenues.

[33] The term, "least cost," was never intended to mean lowest economic cost. It was intended to be a catch phrase for optimization. When critics suggested that the lowest price option might not be optimal, advocates of "least cost" planning largely abandoned that nomenclature and substituted in its place "integrated resource planning," to better describe what they believed to be a balanced approach to optimization.

[34] There were scattered and sporadic efforts to deploy dynamic pricing (primarily time of day), automated dispatch of demand (e.g., central control of hot water heaters and air conditioners), and interruptible rates, but only the last of those three were widely used.

[35] This recognition led to the development of de-coupling sales and revenues, or, revenue caps. The concept, which, in one variation or another, has been implemented in several states, was to allow rate adjustments on a periodic basis to allow for recovery of revenues lost to reduced sales. The basic idea was to remove the disincentive for utilities to develop and deploy demand-side management and conservation programs by assuring that lost sales would not result in a failure to meet a company's revenue requirement. There is considerable controversy about whether revenue caps simply compensate for lost revenues due to energy efficiency programs, or, rather, as some contend, they tend to socialize many risks that ought not to be socialized.

not necessarily consistent with how utilities saw their interests. Thus, while federal regulators were envisioning a relaxation of regulation through the introduction of competition, many state regulators saw a need not to relax, but rather to strengthen regulation. The only area of convergence in those otherwise contradictory paths, was in regard to the question of new generation. Both federal and many state regulators came to believe that the old regime of utilities planning and then building new generation themselves for their own rate base, had become obsolete. Independent generators or co-generators may be able to build and operate plants more efficiently, so they should be provided access to the market by compelling utilities to bid for new supply rather than simply building it themselves. Many state regulators were also persuaded that making it more difficult for utilities to build new generating stations, and thereby bulk up the rate base on which they would be allowed to earn a return, would compel utilities to turn their attention elsewhere in looking for profit centers. Energy efficiency, they hoped, is where utilities would direct more of their focus. Thus, while the policy divergence between state and federal regulators remained wide, the agreement on the use of competition to procure new energy supply was a critical common denominator at both levels of regulation.

By the 1990s, however, IRP efforts were substantially reduced, or, in some cases, discarded entirely, as many, although certainly not all, policymakers and regulators at the state level moved away from a focus on planning toward promoting competition. Rate of return regulation was challenged from other perspectives as well, not only because of the perverse incentives in regard to energy efficiency,[36] but also because it penalized efficient service providers while rewarding inefficient ones. This was because under most commonly applied methods for determining rate of return, the rate was set to reflect investor expectations. Thus an investor would demand a higher rate of return to put his capital to work for a weak performer

[36] *See* Footnote 26.

than for a strong one. It was also contended by some that regulators “confiscated” efficiency gains by utilities by capturing those gains and returning them to consumers by reflecting such expectations in future rates.

While those critiques may or may not have been accurate, they did lead to consideration of such alternative ratemaking schemes as price caps and/or various types of performance-based rates.[37] An additional factor that led to investor fears in the 1970s and 1980s was of imprudence disallowance by regulators (particularly in the area of nuclear power). Some contended that this concern limited the availability of capital and contributed to utility reluctance to invest in such capital intensive assets like new generation. Indeed, fear of disallowance reinforced an inherent bias in the regulated electric utility industry, namely adversity to taking on undue risk, whether it be capital intense projects or even technological innovation.[38] The result was that electric utilities were more “regulatory-driven” rather than “customer-driven.”

The public policy response to the confluence of these circumstances was to rely more and more on competition to achieve the desired results of efficient and reliable service. The expectation was that competition would spur cost reduction and efficiency gains, increase quality of service, introduce new products and services and stimulate investment in grid infrastructure. While energy efficiency programs were not entirely done away with, there was a common assumption that competitive markets would produce price signals that would allow customers to make intelligent choices without regulatory intervention through utility demand-side

---

[37] It is worth pointing out that many commentators regard price caps as little more than rate of return with special treatment of regulatory lag.

[38] This risk of adversity by utilities, of course, further opened the door for new entrants in the generation market. For a variety of reasons, some linked to more appetite for risk, but also linked to access to greater leveraging and lower costs of capital, to the different risk/reward ratio for unregulated generators than for regulated ones, and to the nature of purchased power arrangements that often reduced riskiness for non-utility generators, new entrants to the generation market were often more enthusiastic about building power plants than traditional utilities.

management programs.[39] New technologies were making newer generating sources more efficient, and the increasing integration of utilities and non-utility generators on the grid made use of these smaller sources available to larger markets.[40]

While about half of U.S. jurisdictions adopted some kind of restructuring/retail competition plan, about half did not,[41] citing skepticism about the virtues of restructuring or lack of need to change the status quo.[42] However, even where the competitive retail markets did exist, they were still generally lacked the robustness economists would associate with full scale competitive markets. Notably absent, particularly for non-industrial customers, were meaningful price signals, sophisticated communications, demand response mechanisms, and real time price response opportunities that are ordinarily characteristic of competitive markets. In short, while electricity demand was not entirely inelastic, its elasticity was limited by weak pricing methodology and a technological gap. The absence of both pricing and technology to enable meaningful customer response from customers other than large industrials, was compounded by the customer behavior patterns that have been formed from a century of limited choices.

---

[39] The assumption that the prices produced by competitive markets would enable customers to make intelligent choices was highly ironic because few jurisdictions, if any, actually reformed electricity pricing that would effectively communicate those signals to end users. It is one of the most curious aspects of retail restructuring in the states of the U.S. that real pricing reform was not part of the effort to open up retail markets. It is particularly ironic, given that the emerging wholesale markets at the time were being meticulously designed to produce highly refined and precise price signals.

[40] Severin Borenstein and James Bushnell, "*Electricity Restructuring: Deregulation or Reregulation? 23 Regulation 2*."

[41] It was widely believed at the time that the introduction of competition would produce lower prices. While, in hindsight, that would appear highly dubious as an *ipso facto* assumption, it is true that the introduction of wholesale market competition was likely to produce a levelizing of prices between states that had previously been divided into high and low cost energy markets. The result was that retail competition, even before the California implosion, had come to be seen as highly desirable in high cost states and less desirable in low cost ones. Thus, the states that adopted retail completion tended to be those with high costs, while those with low costs preferred to maintain the regulated monopoly regime.

[42] The fallout from the California energy crisis essentially stopped the expansion of retail competition in its tracks. While that crisis was the result of several factors, human and natural, that were *sui generis,* to the California market, policymakers in many other jurisdictions made sweeping conclusions regarding the efficacy of retail competitions.

Independent System Operators and Regional Transmission Systems[43]

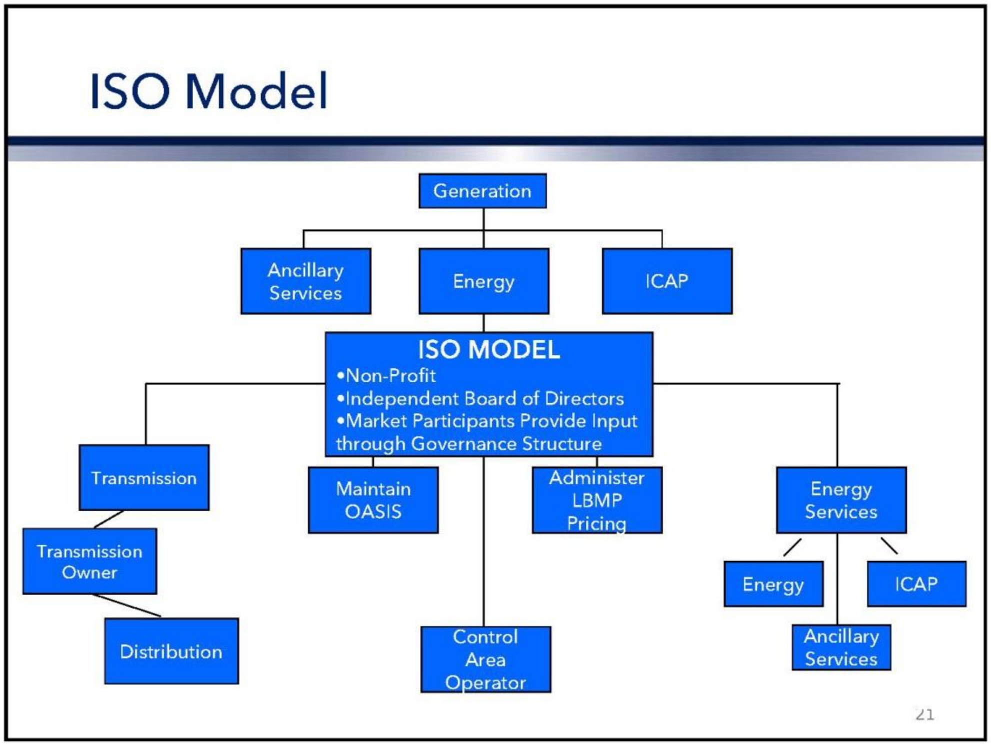
As mentioned above, Order 888 established federal open access rules for the American transmission system. It required transmission-owning utilities to set non-discriminatory rates for transmission access. It also suggested that states and industry participants develop regional organizations and supported the development of ISO-type markets by suggesting so-called ISO principles. The ISO'ss are required to be not-for-profit entities with no proprietary interests in the outcome of competition among players in energy markets. Over time, their obligations have come to include (1) carrying out all day to day operations of the grid in their footprint, conduct dispatch, operate day ahead and other markets (e.g., capacity markets where they exist), (2) mitigation of market power, (3) oversight and facilitation over participatory transmission planning processes, (4) making cost allocation determinations in regard to new transmission, (5) establishing demand-side response programs, (6) assuring reliability within their region, and (7) managing or establish pricing for transmission congestion.

They are also required to have an independent market monitor charged with real time observation of the market and with an obligation to publicly report on market problems and/or abuses in the market. The ISOs must be governed by a Board of Directors with no ties to any market participants, and must exercise its powers through a process that allows input from all interested parties. All RTO decisions are also subject to appeals to the FERC by any party who believes he/she has been materially harmed by a decision, or who believes something occurring within the RTO is contrary to law or policy. Thus, while the RTOs own no transmission assets, they actually manage the grid and operate the market within the footprint in which they operate.

[43] Independent System Operators (ISO) and Regional Transmission Organizations (RTO) are,,perhaps, technicaly distinguishable. RTO is a more generic term that can be used to describe a broad array of transmission related institutional arrangements, while ISO's area more specific, perhaps more fully evolved form of RTO. For purpose of this paper, however and the subject matter discussed, that distinction may be disregarded and the terms should be read used interchangeably and synomously.

They also effectively operate as a kind of regulatory authority with powers delegated by the FERC, but also subject to FERC's oversight and review.

ISO principles included: fair and non-discriminatory ISO governance and tariffs, financial independence of the ISO, responsibility for the reliability of the system, incentives for good ISO management and the use of dispute resolution as the first resort. The ISO model is depicted in the graph below.[44]

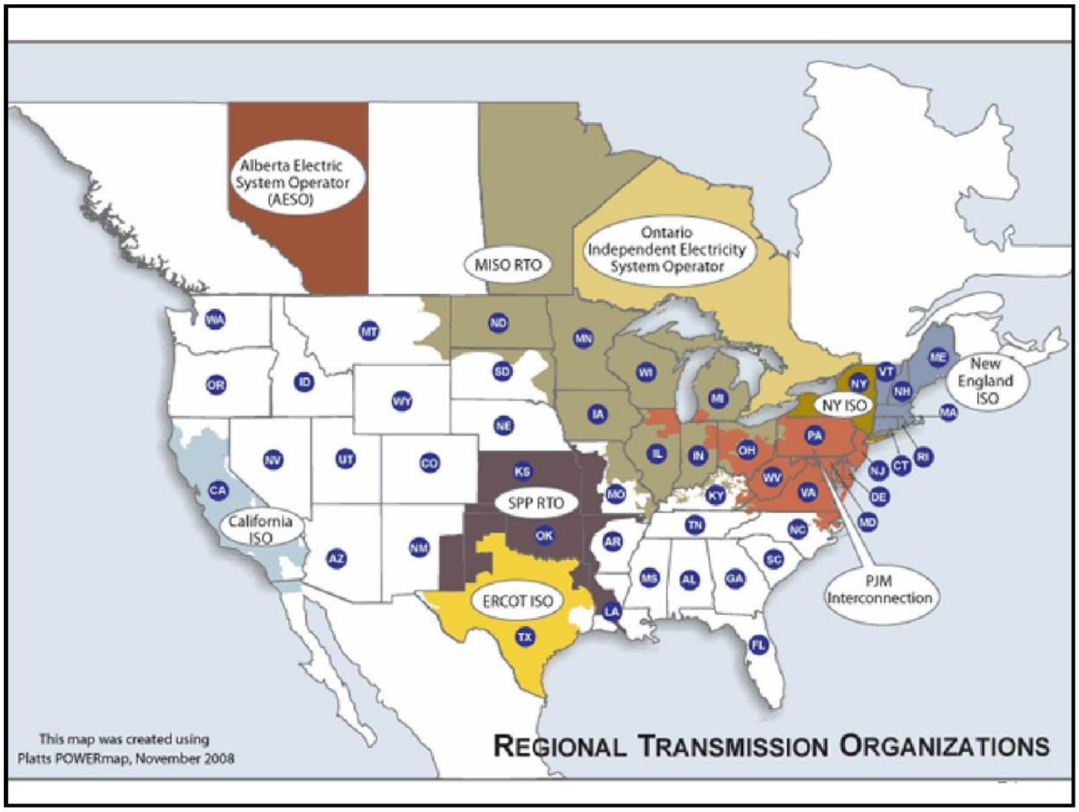


The first ISOs developed in California (1997) and the Northeastern USA, PJM (1997), New England (1999) and New York (1999) power pools. As participants were left to develop their own systems according to the ISO principles, market design varied. In California, both a separate ISO and [DA Power Exchange (PX)] based on zonal pricing were established. PJM implemented an integrated market design allowing real time energy auctions to lead to unit

[44] Extracted from Building Out the Grid.

commitment schedules and location marginal prices. PJM also pioneered financial transmission rights ("FTRs") that hedge locational congestion charges.

The model in New England calculated a single pool-clearing price and out of merit generators on a pay-as-bid basis (mitigated). As mentioned above, in 1999, FERC issued Order 2000, which described FERC's position on regional transmission organizations which would have the authority to police the ISO boundaries and conduct regional planning. Again, ISO development was incentivized, but voluntary. The following chart illustrates the U.S. and Canadian ISOs.[45]



In July of 2011, FERC issued Order No. 1000, a rulemaking that reforms its policies on transmission planning and cost allocation. The intent of Order No. 1000 is to open barriers to transmission development and ensure that the costs of new transmission are allocated to those

[45] Extracted from Building Out the Grid.

who benefit from the project. The reforms may lead to more opportunities for transmission investment, particularly in renewable energy projects and transmission projects designed to bring renewable energy resources onto the grid. Order No. 1000 was issued to improve regional planning and interregional coordination efforts.[46] It was also issued in response to the 7th Circuit's decision in *Illinois Commerce Commission v. FERC*, which overruled FERC's order on PJM's cost-allocation methodology.[47] FERC thus realized that it needed to set a new rule to guide cost allocation that could be consistent across regions.[48]

Order No. 1000 is intended to open barriers to transmission development and ensure that the costs of new transmission projects are allocated to those who benefit from the project. Order No. 1000 addresses regional planning by requiring that public utility transmission providers participate in a regional transmission planning process that produces a regional transmission plan. It also removes any federal rights of first refusal from FERC-approved tariffs and agreements.[49] Order No. 1000 improves coordination between RTOs for new transmission facilities. It also requires that public utility transmission providers amend its Open Access Transmission Tariff (OATT) to provide for the consideration of transmission needs driven by

---

[46] Catherine McCarthy, Elias Farrah and Shamai Elstein, FERC Transmission Update, March 8, 2012 for Dewey & LeBoeuf LLP ("FERC Transmission Update").

[47] FERC approved a "postage stamp" right for a new facility built in PJM, where all utilities in the PJM region would contribute a pro rata share of such facilities. The 7th Circuit held that FERC failed to show that the postage stamp methodology used in that instance was justified. The Court, in essence, instructed the FERC that it could not merely socialize transmission costs across the network. Rather, it had to justify its allocation of costs based on who would benefit from the facility whose costs were being allocated. While the Court noted that mathematical precision was not being required for cost allocation, the Commission had to, at least, make a reasonable effort to allocate costs in accordance with the benefits to be derived. Interestingly, concurrent with the *Illinois Commerce Commission* case, there was a serious effort in the U.S. Senate to enact a law that would require a higher degree of precision in allocating costs. That law has not been passed as of yet.

[48] FERC Transmission Update.

[49] The right of first refusal (ROFR) was the right incumbent transmission owners retained under transmission ownership agreements in each of the RTOs to have the first right to build new transmission lines called for by the RTO in its service territory. By abrogating ROFR, the FERC is injecting a new level of competition in the expansion of transmission grid, by allowing new entrants into that market.

public policy requirements in the local transmission planning process.[50] These policies include the integration of wind energy and other renewables into the transmission grid. Order No. 1000 also requires public utility transmission providers to participate in a regional transmission process that has both a (i) regional cost allocation methodology for the cost of new facilities selected in regional transmission plans and (ii) an interregional cost allocation methodology for the cost of certain new transmission facilities that are located in two or more neighboring regions (and are jointly evaluated by those regions).[51]

Retail Access

Decisions regarding open retail access in the United States, as previously noted are made at the state level. Roughly half of the states have retail third-party competition and retail access.[52] Thus, in theory there is widespread retail access. In fact, even in states with open retail competition, many customers choose not to opt for alternative suppliers. There are a variety of reasons for this. One is that the potential savings are often insufficient to incentivize consumers to shop. That disincentive is enhanced by the fact that, as discussed elsewhere in this paper, small customers do not receive any meaningful price signals. A second reason is that the startup costs for new entrants in the mass market of retail competition pose a major barrier for new entrants to the market, especially given the advantages enjoyed by the incumbent utilities. Those advantages include privileged access to customer data, pre-existing infrastructure. This include back office operations, billing and metering, sales and service crews, and deep knowledge of local circumstances and pre-existing relationships with customers. For larger consumers, particularly industrial, tariffs generally yield far more effective price signals.

[50] FERC Transmission Update.
[51] FERC Transmission Update.
[52] Policies and practices in the US vary widely. In Cleveland, Ohio, for example, there are competing distribution companies with duplicate wires, one owned by the municipality and the other one, private.

Crucial to the retail access debate in the United States is the nature of default service that customers receive if they do not choose an alternative supplier. There are two issues regarding default service, the first being who provides it, and the second, the nature of the product itself. In regard to the provider, most states decided that the default provider would be the incumbent utility. Thus, customers who do not select a new supplier remain as a full service customer of the incumbent. Texas, on the other, hand, determined that the incumbents would no longer be able to be retail service providers where they were the incumbent utility. Thus, customers were required to either select a supplier, or, alternatively, have one selected for them on a random selection basis.[53]

The theory that led Texas to its decision was that compelling switching would overcome consumer lethargy in a newly competitive market, and would deprive the incumbent of an inherent advantage it might otherwise possess against new entrants to the market.[54]

The default product, itself, can be a powerful carrot or stick that incentivizes customers to choose or not choose a competitive supplier. The more unattractive the default product, the more incentive customers have to choose a competitive supplier. Conversely, the more attractive the default product, a lesser incentive exists to choose a competitive supplier. States have grappled with how and where default products should be regulated, or whether utilities should have more thoughtful energy procurement policies.

---

[53] The Texas model, or variations of it, were proposed in other states, Ohio and Pennsylvania, for example, but the idea was rejected in the face of powerful opposition by the utilities.

[54] Whether consumers "opt in" or "opt out" is a policy issue that has attracted a fair amount of controversy. "Opt in" is where the customer remains with his/her supplier unless he or she explicitly chooses another one. "Opt out" means that a customer will have a supplier selected for him/her unless he or she explicitly opts out. Most consumer advocates favor "opt in" as the customer is empowered to decide, as opposed to "opt out" where decisions are made for the customer unless the consumer takes action to avoid the choice being made. There has also been concern about the practice of "slamming," where a customer is switched without his/her consent by unscrupulous operators who profit from "false switches."

Some states, like New Jersey, Illinois and Massachusetts engage auction processes where a utility auctions out its full requirements, or a rough portfolio of requirements to serve its default customers. Pennsylvania has been grappling with how default service should be offered and regulated. Initially Pennsylvania regulators set a fairly high default product price that provided a margin intended to provide head room for new entrants to compete and which provided customers with a price incentive to switch. That policy set off a storm of protest from advocates of various sorts who wanted a default product price that was closer to costs rather than being designed to allow new entrants to compete. Eventually that led to Pennsylvania lawmakers putting price caps on default service that expired in 2010. Stakeholders and the Pennsylvania Public Utility Commission ("PAPUC") have struggled to come to a consensus on pricing mechanism or method.[55] Utilities in Pennsylvania have filed default service plans, and have proposed both retain opt-in auctions and customer referral programs.

The PAPUC's expected Final Order in the Retail Markets Investigation, whereby the PAPUC has been seeking ways to improve the state's retail markets, is expected in the fall of 2012.[56] This Final Order is expected to yield guidance with respect to the nature of required default service plans.

(A) ERCOT

The Electric Reliability Council of Texas ("ERCOT") is considered one of the most robust competitive electricity markets in North America.[57] ERCOT has a unique place in the American electricity sector. ERCOT is regulated solely by the Public Utility Commission of

[55] David B. MacGregor, Anthony D. Kanagy, Default Service in Pennsylvania, 2009, available at: http://www.postschell.com/docs/publications/557.pdf.
[56] *See* "Electricity Default Service Plans- the Next Generation," Hawke McKeon & Sniscak LLP, February 24, 2012, available at http://www.hmslegal.com/blog/entry/electricity-default-service-plans-u2013-the-next-generation.html.
[57] Electricity Market Reform: An International Perspective at p. 383.

Texas ("PUCT"). Because it is not electrically synchronized with the Eastern or Western Interconnections, it is outside FERC jurisdiction.[58]

Texas was the last U.S. state to establish a statewide regulatory body in 1978. The Public Utility Regulatory Policy act gave the PUCT jurisdiction over the state's vertically integrated utilities.[59] Competition in Texas advanced in the 1980s via QFs and PUCT's resource planning rules which required competitive bidding in the building of new utility power plants.[60] In 1995, Texas's Senate Bill 373 required that the establishment of rules guiding wholesale competition ensure non-discriminatory access and create an ISO.[61] PUCT, intending to level the playing field among incumbent utilities and IPPs, established generator friendly interconnection rules and postage stamp transmission pricing in ERCOT. As a result, many national energy and utility companies have entered the ERCOT market, including Exelon, American Electric Power, Calpine, Constellation, Suez Energy and American National Power among others.[62]

Later legislation gave PUCT the authority to oversee markets and investigate market manipulation. In 1999, Senate Bill 7 was passed, which dilutes market power by stating that no generator was allowed to control over 20% of the installed generating capacity in ERCOT.[63] Power generation companies associated with a utility of a certain size must sell at auction entitlements to at least 15% of that capacity. Texas allows incumbent utilities to participate in both regulated and competitive activities, but required them to unbundle their functions into separate entities. Codes of conduct between the regulated and competitive affiliates were imposed. These include limits on information exchanges in order to prevent information

---

[58] ERCOT does have ties to the Eastern Interconnection that are not considered to result in interstate transmission. Electricity Market Reform: An International Perspective at p. 384.
[59] Electricity Market Reform: An International Perspective at p. 388.
[60] *Id.*
[61] *Id.*
[62] Electricity Market Reform: An International Perspective at p. 390.
[63] Electricity Market Reform: An International Perspective at p. 392.

asymmetry with competitors.[64] Regulatory oversight over transmission and distribution as monopolies remained.

(B) CA Crisis

The California experience with restructuring was marked by crisis in 2000 and 2001. The crisis was both an electricity crisis and a financial crisis for California Investor Owned Utilities (IOUs). The California crisis set back momentum for retail competition throughout the United States. It was caused by the combination of an extraordinarily poor market design, a severe drought and environmental constraints. It was also caused by a political compromise that, while unanimously passed by the legislature,[65] was, in hindsight, a disaster for the state's energy markets. The California policy made all generation FERC jurisdictional and locked in retail rates, without regard to actual costs of procuring energy. The policy assumed, for no clear reason, that prices would go down in the wholesale market, and that private market participants would emerge to become alternative retail suppliers. These participants, however, did not emerge. Nor did prices go down, they went up. Thus, utilities bought power in bulk at rising wholesale prices, where retail prices were frozen. The utilities were thus forced to buy high and sell low, and bulk purchases did not make up the costs. The crisis was compounded by drought and environmental controls in the state that placed restrictions on the use of certain resources at certain times. Furthermore, the transmission market was poorly planned, with inefficiently drawn zones and a dispatch method in place to deal with congestion. Customers received no price signals, which did not regulate demand in the summer months. The state experienced blackouts and the near bankrupting of several of its major utilities. While the crisis was caused

[64] Electricity Market Reform: An International Perspective at p. 392.

[65] The restructuring effort in California was initiated by the state's regulators who proposed a market design quite different than what emerged from the legislature. The problem was that regulators lost control over a very contentious process and it became highly politicized and, therefore, put in the hands of the Governor and legislature who were quite skilled in developing political consensus, but considerably less skilled in successfully designing markets for electricity.

by faulty market design and bad political decisions, it left a bad taste in the mouths of many states, who drew the blunt political conclusion that competition is not the thing to do.

2. Canada

Canada has no national electricity regulation, rather it is regulated provincially.[66] Much of the Canadian system is part of an integrated North American grid, and under the terms of the Canadian constitution, provinces have ownership of the resources in their territory. Canada has not fully restructured, and the majority of Canada's utilities are owned by the provincial or local governments.[67] In some provinces, integrated utilities are being increasingly functionally unbundled to accommodate wholesale competition. Structures vary widely between provinces. In the Provinces of Newfoundland and Labrador, for example, generation/transmission and distribution/retail are vested in separate entities. Two provinces, however, Alberta and Ontario (as depicted on the RTO map above), have opened wholesale electricity markets and offered retail choice).[68] Five provinces (British Columbia, Saskatchewan, Manitoba, Quebec and New Brunswick) have open wholesale markets and some forms of competition in generation and retail choice.[69] Because of the trade between the U.S. and Canada, the FERC policy of open access in the U.S. has had significant influence in Canada. That is because the FERC has required that any utility seeking access to markets has to, in turn, offer the same access to competitors that they seek for themselves. Since most of the Canadian utilities buy and sell electricity in the U.S., they are compelled to offer open access to competitors if they want to maintain participation in U.S. markets. Thus, in essence, open access in many parts of Canada is perhaps more of a function of U.S. regulation than it is of Canadian policy.

[66] Canadian national regulators do manage the process of licensing electricity exports to the United States.
[67] Electricity Market Reform: An International Perspective at p. 419.
[68] *Id.*
[69] *Id.*

In Ontario, the election of the Progressive Conservative government in the late 1990s the provincial government set out to reduce the size of government and remedy what they saw as the poor performance of the government hydro company led to reform.[70]. In 1998, the Electricity Act laid out the framework for reform, and Ontario Hydro was split into two companies, one for transmission (OPG) and one for generation (Hydro One).[71] To prevent OPG from using its dominant generation position, it entered into a market mitigation agreement with the provincial government. Two agencies were created to oversee the electricity market, namely the Ontario Energy Board (which was pre-existing) and the Independent Electricity Market Operator (IMO). IMO was tasked with dispatch and operating the wholesale spot market.[72]

A crisis precipitated by a heat wave and shortage of nuclear generation caused a tripling of prices in 2002, and the government responded by freezing prices for small customers. The crisis led to government contracting for new electricity supply, and the creation of the Ontario Power Authority in 2004.[73]

Ontario currently has a hybrid market model which includes the Ontario Power Authority, which contracts for supply, integrated system planning and regulated pricing. Wholesale prices are created through the market but moderated by contract guarantees.[74] Prices are determined by the hourly price set in the market that is adjusted to take the various types of contracts prices into account. Contracts are structured to provide either fixed prices, monthly

---

[70] The term "hydro" is a relic of the traditional reliance on hydro resources by Ontario. In fact, the utility has considerably diversified its resources beyond exclusive reliance on hydro.
[71] *Id*. at 423.
[72] *Id*. at 424.
[73] Doug Reeve, Donald Dewees and Iryan Karney, "Current Affairs: Perspectives on Electricity Policy for Ontario," *University of Toronto Press*, 2010.
[74] Energy Policies of IEA Countries, Canada, International Energy Agency, 2009 Review ("Canada Report").

revenue guarantees or guaranteed floor prices. 70% of electricity in the province is provided by OPG.[75]

The Independent Electricity System Operator operates a real-time energy market where electricity demand and supply are balanced with instructions issued to generators eligible to dispatch every five minutes. At these intervals, the IESO collects the best offers from generators and loads to provide the needed amount of electricity.

Alberta began to reform its electricity market in 1995 with the Electric Utilities Act. The goal of the legislation was to attract private sector investment and participation in new generation.[76] Before restructuring, the Alberta electricity sector was comprised of three integrated utilities within concession areas. Electricity assets, however, were owned either by utilities or the municipalities. Electricity was purchased at a regulated, cost of service rate by the government and resold to the utilities for distribution at an averaged price.[77] Reform created an independent transmission operator, to which utilities had to transfer assets. Divestiture of generation was not required, however, it was mandated that incumbents divest the production rights of their generation assets.[78] The production rights, called power purchase arrangements, were auctioned to private investors. Thus, the output of the plants was forced into competitive markets, but the actual ownership of the underlying asset need not have been changed.These auctions began taking place in 2000. In 2003, the new Electric Utilities Act created the Alberta Electric System Operator ("AESO") which is responsible for planning and operating Alberta's system, including upgrades and necessary enhancements. In 2007, the Alberta Utilities Commission Act split the former regulator into the Energy Resources Conservation Board (to

---

[75] *Id.*
[76] *Id*. at 444.
[77] *Id.*
[78] *Id.*

focus on oil and gas development) and the Alberta Utilities Commission (responsible for regulating distribution and sale of electricity).[79]

The Alberta system consists of privately and municipally owned companies.[80] Generation is competitive and transmission and distribution are rate regulated. All electricity in Alberta is sold through the wholesale pool, and it determines spot prices each hour. Generators submit a schedule a day ahead and the system controller sorts offers by price to determine the order. The price of the last offer to be dispatched to meet demand sets the system marginal price each minute. A time weighted average of the marginal prices calculates the pool price for that hour.

More than 200 power pool participants compete to buy or sell power or provide ancillary services. The retail market is open to competition, but residential, farm and small and medium commercial customers have the option to remain on a regulated rate tariff. The default rate is based on market prices.

3. Argentina

Argentina's electricity sector was significantly [81]restructured in the context of privatization programs launched by the Peronist party in 1989. The State Reform Law[82] established a legal framework for the privatization of state resources.[83] Decree 634/91 of 1991 and the Electricity Law (24,065), enacted in 1992 created a legal framework for the transformation of electricity specifically.[84] It included, among other things: (1) the breaking up

---

[79] Canada Report.
[80] Canada Report.
[81] Michael Pollitt, Electricity Reform in Argentina: Lessons for Developing Countries, Cambridge Working Papers in Economics, 2004 ("Electricity Reform in Argentina"), Jose Delfino, the Reform of the Utilities Sector in Argentina, World Institute for Development Economics Research, Discussion Paper No. 2001/74, 2001, available at
[82] The State Reform Law No. 23,696 ("State Reform Law").
[83] Rodolfo Diaz, Reforms of the Nineties in Argentina, Harvard University, 2000, available at
[84] Electricity Reform in Argentina at p. 5.

of state own companies, (2) established a wholesale energy market, (3) created a regulator, (4) defined the powers of the Secretary of Energy and (5) created a Federal Energy Council.

Privatization continued under President Menem, and in 1992 the main state-owned power companies, the major utility serving the Buenos Aires area (where more than half the nation's populations lives) and the national generation companies,[85] Agua y Energia Electrica and HIDRONOR were privatized.[86] Menem-era reform resulted in the break-up of the three vertically integrated state-owned companies into 27 generating units, 7 transmission companies and several distribution companies that were then privatized.[87] More than 80% of Argentina's generation, all of its transmission and 60% of the distribution sector were transferred into private ownership and some cooperative ownership.[88] The state-owned nuclear power generating company remained publically owned.

Under Law 24,605, transmission and distribution were regulated as monopolies. Transmission expansion was planned by a unique "public contest" method where users were required to propose, approve and pay for major expansions, which were then put out to competitive bid.[89] Decisions to approve major expansions were not made by transmission operators or provincial regulatory bodies. Instead, pursuant to the public contest method, the decisions were made by the users of the systems, namely generators, distribution companies and

---

[85] Many of the distribution companies were owned by provincial and not the national government, so privatizing them was not a matter of national policy. The distribution company in Buenos Aires was an exception. It was owned by the national government. Thus it was the first of the distributors to be privatized.

[86] Belizza Janet Ruiz-Mendoza, Claudia Sheinbaum-Pardo, Electricity Sector Reforms in Four Latin American Countries and Their Impact on Carbon Dioxide Emissions and Renewable Energy, *Energy Policy Journal*, Volume 38, 2010, Elsevier ("Reforms in Four Latin American Countries").

[87] Michael Pollitt, Electricity Reform in Argentina: Lessons for Developing Countries, *Cambridge Working Papers in Economics* at p. 2, 2004, available at:

[88] *Id.*

[89] Stephen Littlechild and Eduardo A. Ponzano, Transmission Expansion in Argentina 5: the Regional Electricity Forum of Buenos Aires Province, Judge Business School, Cambridge, December 2007.

large consumers.[90] Potential users or beneficiaries were required to propose and approve expansions to the system, and existing transmission and sub-transmission operators were not allowed to propose expansions.

CAMMESA identified beneficiaries by using the area of influence method, which estimated the changes on the system that would result from the proposed expansion. If 30% of beneficiaries supported the expansion, and less than 30% of beneficiaries opposed it, the expansion could move forward.[91] ENRE was tasked with making sure that the expansion reduced the sum of investment, operation and outage costs in the system as a whole, although few expansions failed this so called "golden rule" test.[92] Approved expansions would be put out to tender under contract, and the bidder offering the lowest annual fee over a specific amortization period won the bid.[93] The public contest method has been criticized. Does the area of influence method reflect usage of the system, rather than the economic benefits of it? Can any centrally prescribed method of cost allocation reflect local conditions? Are distribution companies, given the regulation of their costs and prices, appropriate actors, and were the resulting expansions efficient? Further, proposed lines could be uneconomic, or badly tied. Or a desirable project could be missed if designated beneficiaries, for example, were unable to fund them.[94] The delayed construction of a Fourth Line Expansion projects, however, have gone forward using the method.[95]

Law 24,605 also required open access or non-discriminatory access to the grid by third parties. Generation was treated as structurally competitive, with the creation of a wholesale

[90] *Id.*
[91] *Id.* at p. 9.
[92] *Id.*
[93] *Id.*
[94] Electricity Reform in Argentina.
[95] *Id.* at p. 2.

energy market ("MEM") and generators to receive a uniform rate. CAMMESA[96] manages MEM via the Organismo Encargado del Dispatcho (the Dispatch Management Agency "DMA").[97]

Electricity distribution in the Buenos Aires area, where a substantial portion of the population lives, is regulated under concession contracts. The contracts are for 99 years with price reviews occurring every five years. At the review time, distribution tariffs for regulated customers were to be reset following regulatory assessment by ENRE under an incentive regulation regime. Distributors were responsible for bill collection and given incentives to reduce losses (which were high due to issues like technical inefficiency and theft).[98]

Argentina's wholesale market consists of a spot market and a bilateral contract market. Spot prices are determined hourly as dispatched based on short-term marginal costs. Bilateral contracts are freely negotiated. Dispatch is cost based and price is set on a nodal basis.[99] Ancillary services and transport are included as part of customer tariffs.

Argentina's electricity sector reform was adversely affected by Argentina's severe economic and political crisis in 2001 which caused a devaluation of the peso against the U.S. dollar.[100] This resulted in a widespread defaulting on debt payments by energy companies and a loss of shareholder value. Transener, the transmission company, lost much of itsof shareholder equity value. Distribution and generation companies also posted large losses.[101] International

---

[96]CAMMESA is a not-for-profit joint stock company owned by the association of power generators, the association of large users and the secretariat of energy, with each shareholder having 20% of the company. The Secretary of Energy is the final member.

[97] Another cite: Werner Baer, David V. Fleischer, Economies of Argentina and Brazil: A Comparative Perspective, Edward Elgar Publishing, December 2011.

[98] Electricity Reform in Argentina.

[99] Isaac Dyner, Understanding the Argentinian and Colombian Energy Markets, Electricity Market Reform at p. 601.

[100] Lev. S. Belyaev, Electricity Market Reform: Economics and Policy Challenges,

[101] Decree 1220/1998; Decree 1597/1998; Resolution 136/2000; Resolution 113/2001; Resolution 905/2005; Resolution 1061/2005; Resolution 1835/2005 and Law 26190. Electricity Reform in Argentina.

investors also experienced major losses. In 2004, the U.K. company National Grid sold its stake in Transener for less than 10% of its pre-crisis investment value.[102]

Argentina began creating a national regime for wind and solar energy in 1998.[103] These initiatives featured a taxation structure for wind and solar, where they would pay the value-added tax over a period of 15 years. In addition, a feed-in tariff funded from a wholesale electricity market charge was established, whereby technologies taking advantage of renewable energy sources get guaranteed payments if traded at the wholesale electricity market or supplied as public services.[104] In 2006, Law 26,190 mandated that 8% of national electricity consumption should come from renewable energy sources during ten years.[105] In 2009, Decree No. 562 relating to Law 26,190 went into effect, by which 1015 MW of renewable energy would be installed by 2016, including 500 MW of wind energy, 150 MW of thermal by biofuels and 100 MW of biomass. Thus, the original model for the generation sector shifted from resource indifference into one that embodied within it certain resource preferences to satisfy policy/social preferences independent of their intrinsic economic value.

4. Chile

Chile is widely regarded as the world's pioneer in the restructuring and privatization of electricity markets, which began in the early 1980s.[106] Chile's market reform was rooted in political turbulence. During Salvador Allende's government (1970-1973), 100% of public service companies were owned by the government and end users' tariffs were subsidized.[107] After the 1973 military coup of Augusto Pinochet, the Junta's pro-competitive market ideology

---

[102] *Id.*
[103] Electricity Reform in Argentina.
[104] *Id.*
[105] *Id.*
[106] Fereidoon P. Sioshansi and Wolfgang Pfaffenberger, *Electricity Market Reform: An International Perspective*, Oxford, Elsevier, 2006, at p. 77 ("Electricity Market Reform: An International Perspective").
[107] Electricity Market Reform: An International Perspective at p. 82.

led to reforms in Chile's electricity sector.[108] An extensive privatization process began in the mid 1980s that ultimately resulted in almost 100% private ownership of the electric transmission and distribution systems.[109] The Chilean system has also been tested by crises, including severe drought in the late 1990s and shortages in natural gas imports from Argentina in 2004.

Chile's National Energy Commission ("CNE"), an energy regulatory and advisory body, was established in 1978.[110] Chile introduced a tariff decree to set nodal prices at the level of generation, transmission and distribution in 1980.[111] The enactment of the DFL No. 1[112] in 1982 created a framework where the Chilean electricity supply industry was decentralized and privatized into generation, transmission and distribution segments. The intent of DFL No. 1 was for generation to be competitive, transmission to be an open access regime and distribution to remain a natural monopoly.[113] The Cento de Despacho Economico de Carga (Economic Load Dispatch Center, or "CDEC"), was created to function as an independent system operator.[114] A market was set up between generators and distribution companies for small consumers, and large consumers were enabled to engage in supply contracts with generating or distribution companies.[115]

Chile's electricity sector consists of four distinct interconnection systems, the two largest being the Sistema Interconnectado del Norte Grande (Greater North Interconnected System

---

[108] *Id.* The Junta's reform agenda included the promotion of efficiency in the electric sector through competition in generation and regulation of distribution tariffs.
[109] Electricity Market Reform: An International Perspective at p. 86.
[110] Decree-Law No. 2,224, 1978. Until 1978, Chile's state company, the Emprese Nacional de Electricidad S.A. ("ENDESA"), established in 1943, largely controlled the country's electricity sector. CNE was tasked with electricity policy and planning to introduce efficiencies into the sector. The Superintendencia de Electricidad y Combustibles ("SEC") was created in 1985 pursuant to Law No. 18,480, replacing the Superintendence of Electric Services, Gas and Telecommunications and vested with a supervisory role, including the inspection and security of electric facilities.
[111] Electricity Market Reform: An International Perspective at p. 86.
[112] General Law of Electric Services, Decree-Law No. 1, the Ministry of Mines, 1982 ("DFL No. 1").
[113] Electricity Market Reform: An International Perspective at p. 77.
[114] *Id.* The CDED was created by Decree-Supreme No. 6 of the Ministry of Economy in 1985, which also set rules for transmission pricing.
[115] Electricity Market Reform: An International Perspective at p. 78.

"SING") and the Sistema Interconectado Central (Central Interconnected System "SIC") which serve the majority of Chile's population.[116]

SING carries the load of the mining and industrial sector, including a number of large copper mines, and is a fairly concentrated market, with [3] distribution companies and [3] large independent generators.[117] More efficient natural gas power plants, and the increased availability of domestic and imported natural gas, led to natural gas power plants becoming the base of SING. Increased investment in natural gas plants implied significant increases in SING's installed capacity, which increased from 1277 MW in 1997 to 3596 MW in 2004 (with peak load representing only 40% of installed capacity).[118]

SIC is the largest system in the country, with the majority of its consumption going to small end users. SIC has over 30 distribution companies and 3 large independent generators and a few smaller co-generators.[119] SIC depends primarily on hydro generation, with an increasing percentage of generation coming from natural gas power plants.[120]

Between 1998 and 1999, the SIC region experienced severe drought that negatively affected hydraulic generation. This caused electricity rationing for households in the SIC. Deficiencies in the coordination of the system also caused blackouts in the SING. In 1999, Law No. 19,613 was passed in response to the crisis, which increased SEC control over electric companies. In addition, Law No. 19,613 excluded droughts more severe than ones considered in the calculation of regulated prices from being considered a cause of force majeure. These and other changes in the law greatly increased generator's risk. This rule put a damper on generators' entering into long-term contracts with distribution companies.

---

[116] *Id.*
[117] [Need to update figures.]
[118] Electricity Market Reform: An International Perspective at p. 80.
[119] [Update figures.]
[120] Electricity Market Reform: An International Perspective at p. 81.

The government responded by enacting R.M. Exempt No. 88 which, among other things: (1) required CDEC-SIC generator members to jointly satisfy distribution company demand and (2) also stated that distribution companies without a contract must pay regulated nodal prices and that energy consumption should be distributed among the generators proportionally. Law No. 19,613 is credited with significantly decreasing investment in electric energy supply.

Chile's SING suffered its own crisis in 1999 with two large disturbances in July and September which led to blackouts and outages. Increased electric capacity, without the necessary ancillary services and ability of SING to ensure reliability, led to instability with large consumption increases or the exit of a large power plant. In response, CDEC and SING began to implement a short-term security plan, which included limits on maximum capacity to be dispatched and spinning reserve requirements.

In 2004, Chile's reliance on natural gas from Argentina caused another crisis in the electricity sector. Argentinian natural gas helped to fuel Chile's conversion to more efficient natural gas powered plants. The economic crisis in Argentina led to a decrease in exports to Chile.[121] This led to increased fuel costs and efficiencies for generators that were able to convert to fuel oil, and the need for the industrial sector to invest in back up power. This also caused Chile's electrical system to operate at the limit of its capabilities. The government responded in 2005 with Law No. 20,018, which attempted to incentivize investment in and increase the reliability of the electric system.[122]

[121] Another neighboring country, Bolivia, has substantial reserves of natural gas for export, which it sells to Brazil and Argentina. For political/diplomatic reasons dating back to the War of the Pacific in 1879, when Chile seized Bolivia's Pacific Coast, Bolivia refuses to export gas to Chile.

[122] These incentives included (1) allowing generators to offer incentives to end users to reduce electricity use in times of shortage and (2) price incentives for investments in renewable energy.

Generation, transmission and distribution in SIC and SING are vertically integrated but horizontally unbundled.[123] The generation market is highly concentrated, with the majority of capacity belonging to three large holding companies.[124] Generation ownership is highly concentrated. 67% percent of lines in SIC are owned by two companies; 75% of lines in SING are owned by four companies. 60% of distribution in SIC is supplied by two companies and one company owns virtually all of the distribution companies in SING.[125]

The Chilean wholesale electricity market is comprised of a spot market and a contracts market. Generators are required to sell all of their hourly generation into the SIC and SING, and to buy their hourly contract demand at the corresponding hourly marginal cost projected for demand node.[126] Dispatch and prices are based on an economic merit order. Prices take account of transmission constraints, so generators directly bear those costs. Generators in the SIC and SING cannot bid freely, instead they are dispatched. Imbalances between generation and contract demand are settled at the marginal cost at the respective node. The price paid for peak power is determined every six months by the CNE, based on the annualized cost of a reference peaking unit. Generators can enter into contracts with distributors and non-regulated customers, with the nodes specified in the contracts.

The CDECs maintain service quality, dispatch at least cost, manage the spot markets (calculate prices and performs settlements) and guarantee open access to the transmission system. There is no market in ancillary services, and while the establishment of such markets was addressed in the 2004 Short Law I, the regulations have yet to be drafted.[127] The CDECs

[123] Chile Energy Policy Review, International Energy Agency, 2009 at p. 144 (“Policy Review”).
[124] *Id.*
[125] *Id.*
[126] *Id.*
[127] *Id.* [True in 2009.]

have a board governance structure, with representatives from generators, transmission companies and large users.

Transmission is treated as a natural monopoly with three categories of transmission; (1) trunk systems (the backbone of high voltage systems), (2) sub-transmission system (used to supply demand in specific distribution areas) and (3) additional systems (infrastructure required to connect a generating station or large industrial load to the sub or trunk systems). The CNE draws up ten-year generation and transmission expansion plans every four years, with annual revisions made by the CDECs in intervening years. Construction and operation of new facilities are awarded in an international tender, where annual revenues to be received are also determined. Revenues are fixed for 20 years. Non-conventional (geothermal, wind, solar, biomass, co-generation, etc.) plants with power surpluses of less than 20 MW are exempt from paying all or part of injection tolls for use of the trunk system.[128]

Distribution in Chile is a regulated monopoly, and distribution companies within concession areas serve both regulated and non-regulated customers.[129] Regulated customers pay pursuant to an end user tariff that calculates the sum of the distributer energy and capacity price, the transmission toll and a distribution margin intended to remunerate the distribution company with a profit margin. Tariffs for non-regulated customers are determined between generators, distributors and their customers. Distributors and retailing generators compete to serve non-regulated customers.[130] Transmission pricing has been a matter of some dispute in Chile. In 2004, CDEC created a Panel of Experts, an entity designed to be independently financed by sector participants, to decide these disputes. The Panel of Experts' decisions are final and cannot

[128] *Id.* at p. 149.
[129] *Id.* at p. 150.
[130] *Id.* at 154.

be appealed.[131] In 2007, renewable energy sources, including bioenergy from firewood and large hydro accounted for 22% of Chile's primary energy supply.[132] Biomass is a large component, providing 16% of primary energy supply.[133] Chilean law provides that renewable generating plants with power surpluses supplied to the transmission system of 20 MW or less do not pay (or receive a discount) of tolls for access to the trunk system.[134] This ultimately means that renewable units of less than 9 MW do not pay charges and those with a capacity between 9 MW and 20 MW pay only for power exceeding 9 MW. Units above 20 MW pay the full toll amount.[135]

5. U.K.

Britain, after Chile, was one of the first countries to reform its electricity industry. Britain's electricity sector was fully nationalized by the Elecrtricity Act of 1947.The Central Electricity Generation Board owned transmission and generation in England and Wales. Area Boards bought and distributed bulk power. Regional franchises were held by the North of Scotland Hydro-Electric Board and the South of Scotland Electricity Board.[136]

Britain and Wales undertook restructuring in the late 1980s to increase efficiencies and replace the top down structure with a market-driven system.[137] The Electricity Act in 1989 established a legal for restructuring and appointed a regulatory body. In 1990, Britain began restructuring, breaking up the Central Electricity Generation Board ("GEGB") and establishing the Electricity Pool. The Electricity Pool was created as a compulsory bulk spot market that set

---

[131] *Id.*
[132] *Id.* at p. 159.
[133] *Id.*
[134] *Id.* at 150.
[135] *Id.*
[136] This section focuses on Britain and Wales, with lesser mention of Scotland and Ireland.
[137] This section focuses on Britain and Wales, with lesser mention of Scotland and Ireland.

merit order and wholesale electricity prices.[138] In addition to the Electricity Pool, most generators and suppliers entered into bilateral contracts. 60% of conventional generating capacity was placed with National Power ("NP") and the remainder was placed in PowerGen ("PG").[139] The grid was transferred to the National Grid Company ("NGC"). NGC also functioned as an ancillary service provider. Nuclear stations were transferred to Nuclear Electric and kept in public ownership until 1996. In 1991, 60% of NP and PG were sold to the public. In 1993 and 1994, coal contracts were extended and replaced and the coal industry was sold to a single private company. The second tier market was established in 1994 and generators agreed to divest within two years.

In 2001, the Electricity Pool was replaced by New Electricity Trading Arrangements ("NETA"). NETA emerged as four voluntary and interdependent markets operating over different time scales.[140] NETA evolved into the British Electricity Trading and Transmission Arrangements ("BETTA") in 2005. National Grid's function is to make sure that demand and generation are balanced and transmission constraints respected. Most electricity is traded bilaterally (or internally, for integrated firms).[141] NETTA developed rules to cope with imbalanced positions (the Balancing Code) and the methods through which National Grid buys and sells power (the Grid Code, the Connection and Use of System Code and the System Operator-Transmission Owner Code).[142]

Changes to the code are ultimately decided by the Gas and Electricity Markets Authority, the industry regulator in Britain. Pursuant to the Balancing Mechanism, generators can volunteer

---

[138] David Newberry, Electricity Liberalisation in Britain: the Quest for a Satisfactory Wholesale Market Design, The Energy Journal Special Issue on European Electricity Liberalization, June, 43-70 at p. 3 ("Electricity Liberalisation").
[139] *Id.*
[140] Newburry at p. 17.
[141] Richard Green, Are the British Electricity Trading and Transmission Arrangements Future-proof? Institute for Energy Research and Policy, University of Birmingham, 2010.
[142] *Id.*

offers to supply power to the market and bids to buy from it. Large customers can also participate in demand response. The system operator will accept more offers to sell power if demand is unexpectedly high or plant failures reduce output. In the case of a transmission constraint, the operator sells back generation on the exporting side of the constraint and buys an equal amount of power on the importing side.

The transmission grid in the U.K. is considered to be relatively strong and well developed, with generation concentrated in the north and demand concentrated in the south.[143] Transmission pricing was developed so that generators and consumers pay annual fixed charges that do not depend on location (by zone) and their peak demand or capacity. The costs of transmission losses and constraints are socialized.[144] This has been criticized because when generators don't bear transmission losses, merit order is distorted.[145] Transmission charges are designed to reflect the long-run marginal cost of transporting one additional MW at any given node, and are modeled based on forecasts.[146] The Transmission Network Use of System charges are calculated on an annual basis for the country's generating and demand zones. Users bear the direct costs of connecting to the grid through a transmission connection charge.[147] National Grid devises transmission charges, and Ofgen decides whether to approve them.[148]

In 1996, the U.K. launched an incentive scheme for National Grid. The costs National Grid is exposed to (and is incentivized to minimize) are both energy and constraint related. The incentive scheme sets targets based on key components, including reactive power, demand

---

[143] International Energy Agency Member Report: Great Britain, 2006 at p. 111.
[144] Electricity Reform in Europe Towards a Single Energy Market, Edited by Jean-Michel Glachant, Edward Elgar, Cheltenham, U.K., 2009. In addition, the European Union's renewable energy target may require up to 40% of U.K. electricity demand to be met from renewables by 2020. *Id.*
[145] *Id.*
[146] International Energy Agency Member Report: Great Britain, 2006 at p. 111. [New report forthcoming for 2012-this may be too old to cite.]
[147] *Id.*
[148] DECC Network Delivery and Access website, available at: http://www.decc.gov.uk/en/content/cms/meeting_energy/network/deliv_access/deliv_access.aspx.

response, fast reserve foot room, restraints and operating reserves. National Grid is allowed to retain a share of value it creates and bear a share of any costs when targets are not met.[149]

Great Britain, along with Germany, has been a leader in climate policy.[150] It has exceeded its Kyoto target for the reduction of greenhouse gases ("GHG"), achieving a reduction of 25% in 2010.[151] In May of 2011, the U.K. government adopted a GHG reduction target of 50% relative to 1990 levels for the period 2023-27.[152] BETTA, however, is an energy-only market and does not offer capacity payments. National Grid is not responsible for directly commissioning capacity.[153] Wind penetration will change the market conditions faced by conventional generators.

Currently, generators in the U.K. face several risks, including: (1) offtake risks related to the sale of power, (2) balancing risks (including those related to participating in intraday markets and avoiding exposure to the cash out price), (3) credit risks, (4) price risks (often managed by hedging) and (5) basis risk (the risk of deviation between the market price and reference (contract) prices.[154] Risk can be a challenge for independent generators who compete with vertically integrated power companies who have, in effect, a natural hedge between generation and supply.[155] The U.K.'s Department of Energy & Climate Change ("DECC") has identified a number of barriers to entry to the U.K.'s electric generation markets, including costs and

[149] Guilherme Luiz Susteras, Graham Hathaway, Jeremy Caplin and Graham Taylor, Experiences of the Electricity System Operator Incentives Scheme in Great Britain, available at: http://www.cidel2010.com/papers/PAPER-37-27022010.PDF.
[150] Martin Janicke, Dynamic Governance of Clean Energy Markets- Lessons from Successful Cases, World Renewable Energy Congress 2011, Linkoping, Sweden.
[151] *Id.*
[152] *Id.*
[153] Will Steggals, Robert Gross and Philip Heptonstall, Winds of Change: How Wind Penetrations will Affect Investment Incentives in the GB Electricity Sector, Energy Policy, 2011.
[154] *Id.* at p. 90.
[155] *Id.*

complexity of participation, limited routes to market for independent generators and low levels of liquidity.[156]

The DECC has engaged in projects to enhance the transmission network and increase its ability to meet the 2020 renewable targets. These projects have included a transmission access review that resulted in a "Connect and Manage" regime in 2010. The project has reduced connection times for 69 large generation projects by an average of six years.[157] Constraint payments are, however, socialized. The U.K. government has also worked with DECC to develop a regime for offshore transmission. In addition, the U.K. government has worked with industry participants through an Electricity Networks Strategy Group to produce an analysis on the upgrades necessary for meeting the 2020 targets.

The U.K. government has also been active on research and development into storage technologies. Efforts include a low carbon investment funds, innovation funds and an energy technology institute that supports demonstration projects.[158]

In 2011, the U.K. government passed Energy Act 2011. The act provides for changes in the way energy efficiency measures are provided and lays the framework to secure low-carbon energy supplies and competition in energy markets. Energy Act 2011 provides a financing mechanism for providing fixed improvements in energy efficiency to households and businesses through a charge on energy bills. By 2018, it will be unlawful to rent residential or business premises that do not reach a minimum standard for energy efficiency.

Energy Act 2011 also amends the major acts governing the utility industry, including Gas Act 1986, Electricity Act 1989 and Utilities Act 2000 to empower the Secretary of State to create

---

[156] Planning Our Electric Future: a White Paper for Secure, Affordable and Low-Carbon Electricity, Department of Energy & Climate Change, July 2011 ("DECC Report").
[157] *Id.* at p. 99.
[158] Id at p. 108.

a new Energy Company Obligation that will take over existing obligations to reduce carbon emissions.

Also in 2011, the DECC issued a White Paper that set forth a reform package designed to meet the power sector's energy and security challenges, including renewable targets. Key elements of the reform package include: (1) a carbon price floor to reduce investor uncertainty and incentivize investment in low carbon generation, (2) new long-term feed-in tariffs to provide incentives for low carbon generation, (3) an emissions performance standard set at 450gCO2/kWh to enforce a requirement that all new coal-fired stations are built with CCS technology and encourage short-term investment in gas and (4) a capacity mechanism, including demand response and generation, to ensure the security of the U.K.'s energy supply.[159]

The DECC White Paper also discusses the use of RPI-X price cap regulation of the electricity network. It concluded that such regulation was not amenable to a future involving renewables, low carbon and new technologies. Instead, it proposed a price control approach called Revenue set for Incentives, Innovation & Outputs, where the regulator will set outputs, based on a level of customer engagement, with incentives for efficient delivery and innovation. In order to strengthen the retail market in Great Britain, the White Paper proposes to limit retailers to one standard tariff per payment method with a common fixed charged to be set by the regulator.

6. Germany

Germany has Europe's largest power market and its transmission network is connected to nine neighboring countries. Coal is Germany's main source for power generation. Historically, the German electricity sector was not an institutional monopoly. Rather cartel agreements,

[159] DECC Electricity Market Reform website, available at: http://www.decc.gov.uk/en/content/cms/legislation/white_papers/emr_wp_2011/emr_wp_2011.aspx.

legally enforced by demarcation contracts, prohibited competition. Restructuring sought to strike the cartel agreements under the authority of the Cartel Office. Network access rules were arranged collectively via association agreements. Technical and administrative rules emerged, while agreements on the terms of network charges were the responsibility of network owners. Association agreements did develop accounting principles to calculate access charges. Network access and network charges did however, come into the purview of the Cartel Office. To strengthen the Cartel Office, Germany legislated an essential facilities doctrine in 1998. This doctrine mandated that network access should be non-discriminatory.[160]

The German electricity sector was restructured in 1996 as Germany began implementing the EU Directive with its Energy Act of 1998. The Energy Act required full market opening, which at that time was unusual for EU countries. Germany's electric system is vertically integrated, with four privately owned utilities owning and operating generation and the grid.

The four transmission system organizations ("TSOs") in German are 50Hertz Transmission GmbH, Amprion GmbH, EnBW Transpornetz AG and TenneT TSO Gmbh. There are, however, a number of firms owned by municipalities. The Energy Act, however, did not implement strong rules on unbundling. Also worth noting, the Energy Act chose negotiated third- party access. Thus, the German electricity system did not have a specific regulator assigned to it. Network access was determined by voluntary negotiation under the auspices of the Cartel Office. The newly liberalized German market, however, proved hostile to new entrants. Reasons for this included the difficulty of obtaining new plant sites and low wholesale prices. Network access arrangements were biased against third parties and complaints of

[160] Electricity Market Reform: An International Perspective, Energy Policy and Investment in the German Power Market at p. 247.

discrimination were persistent. Gas taxes also discouraged new entrants (the primary gas tax was abolished in 2005).[161]

A July 2005 amendment of the Energy Act created the Bundesnetzagentur, or BNA, the German sector-specific regulator with authority over the electricity network.[162] Ordinances in 2006 and 2007 provided general requirements for opening distribution networks and the general terms and conditions for distribution. Power stations were to be allowed access to the network where technically possible. In 2009, Germany adopted incentive based regulation, rather than cost based regulation to spur efficiency.[163] It has been argued that cost-based regulation, however, is needed in order to create long-term network investments.[164]

Thus the German electricity market is highly decentralized with market participants responsible for planning their participation, with the system operator in charge of maintaining the balance between generation and demand.[165] In July of 2009, the European Network of Transmission System Operators for Electricity ("ENTSO-E") took over operations of Europe's TSOs, including Germany's. While the entire German energy market consists of one price area, ENTSO-E created strong interconnections to neighboring countries.

The German electricity market comprises a futures market, day-ahead (spot) market and intraday market (organized by the European Energy Exchange and European Power Exchange "EPEX") and reserve markets (operated by the TSOs). The day-ahead market features a central daily auction where demand and generation bids are matched to determine an hourly price. In

---

[161] *Id.*
[162] *Id.*
[163] Verordnung über die Anreizregulierung der Energieversorgungsnetze, BGBl. I, 2529.
[164] Electricity Market Reform: An International Perspective, Energy Policy and Investment in the German Power Market at p. 253.
[165] Friedrich Kunz, Improving Congestion Management- How to Facilitate the Integration of Renewable Generation in Germany, Dresden University of Technology Chair of Energy Economics and the Berlin University of Technology Workgroup for Infrastructure Policy, July 2011 ("Integration Report").

the case of international trades, restrictions are placed according to the net transfer capacity between countries, which is determined by procedures agreed upon by specific countries.[166]

Market participants can trade at the power exchange or bilaterally. Plant generators must inform the responsible TSO of their proposed timetables by the early afternoon for the next day. Similarly, market participants can use the intraday markets through the EPEX platform or on a bilateral basis (but must inform the TSO of dispatch 15 minutes prior to real time for each 15 minute interval). Operators may ease network congestion through technical switching actions or market-based methods, such as cost based re-dispatching of power. Significant wind generation increases the costs of congestion management in the country.

Germany has required utilities to accept the feed-in of electricity from renewable sources since 1991, when the Electricity Feed-in Law required remuneration at 90% of the retail rate.[167] The Renewable Energy Sources Act in 2000 required guaranteed stable feed-in tariffs for up to twenty years to provide favorable conditions for renewable electricity production. As a result of these and other policies, Germany has one of the largest renewable installed capacities in the world.[168] The German power market successfully operates with 25 gigawatts of installed wind power capacity and 7 gigawatts of installed solar power capacity.[169] The majority of German wind farms are located in the northern and eastern parts of the country, where wind potential is highest. The potential for solar generation, consisting of distributed photovoltaic ("PV") resources, is highest in southern Germany and islands in the Baltic Sea.

---

[166] The Integration Report at p. 4. Germany joined market coupling procedures initiated by France, Belgium and the Netherlands in 2010. The Polish and Czech Republic borders are allocated through explicit auctions. *Id.*

[167] Manual Frondel *et al.*, Economic Impacts from the Promotion of Renewable Energy Technologies: the German Experience, Ruhr Economic Papers, No. 156, 2009.

[168] Large-Scale Wind and Solar Integration in Germany, Prepared for the Bonneville Power Administration Technology Innovation Office and the U.S. Department of Energy, February 2010 ("DOE Report on German Solar and Wind") at p. vi.

[169] *Id.*

Germany's successful integration of solar and wind resources has been attributed to several factors, including the globalization of wind power production deviation, forecast accuracy and sophisticated scheduling intervals. All German wind power production and deviation are virtually combined on a 15-minute average basis and then distributed to the four TSOs. Each TSO must balance wind energy proportional to consumption or load in each control area. PV is shared on a monthly average. German wind forecasting is highly developed, with data of up to ten wind forecast service providers in use at the same time, and a root mean square day-ahead forecast error below 4.5%. 15-minute scheduling intervals are used by German TSOs within control areas, which can change at any time before and sometimes after the dispatch interval. Bilateral trades can also be 15-minute based. Inter-control area exchanges are based on one-hour intervals.

7. Australia

Australia began restructuring of its electricity sector in 2004. Prior to reform, the vast majority of Australia's electricity was supplied through vertically integrated state-owned monopolies.

Victoria and New South Wales are the most populous of Australia's eight states and territories. The majority of Australia's population lies along the coast from Adelaide in South Australia to Cairns in North Queensland, resulting in a long, thin interconnected grid called the NEM. The island of Tasmania is connected by the high voltage Direct Current transmission line, Basslink, to the mainland of the continent.insert status of connection.] Customer demand is split almost equally between households and industry. The electricity system in Australia is mainly coal based, with limited hydro capacity and gas usage. States each have their own pricing node, and there is limited congestion between states. Queensland, Victoria and New South Wales are electricity exporters.

The reform process in Australia began in the early 1990s, with Victoria. The Liberal (Conservative) government prioritized competition in supply, and 7500 MW of generation was split into seven generating companies. Transmission became a single business and five distribution/retail businesses were established. A regulatory body, the Office of the Regulator General ("ORR," later the Essential Services Commission "ESC") was established. The Victorian Electricity Market began operating in 1994. New South Wales followed in 1996. The NEM commenced in 1998, with national prices set by a National Electricity Code Manager and the Australian Competition and Consumer Commission ("ACCC") setting transmission prices. South Australia privatized between 1998-2003, and Western Australia de-aggregated supply (but left generation as one business) in 2005.

Each state has one transmission owner, and each owner is responsible for planning. In Victoria, a government agency, VENCorp, plans the network with different ownership and operation of the assets. South Australia has a hybrid model. Reformers planned for transmission to be centrally planned and provided. Entrepreneurial interconnects, however, were provided for in the National Electricity Law, and two were built by Transenergie. Issues of how to allow and invest in new transmission have been hotly debated in Australia. The debate has been complicated by the growth of subsidized wind power in the country. Over a thousand MW in wind power were planned for south Australia as of 2009, an area that has a conventional capacity of only 3000 MW.

Australia has a gross pool system that suppliers bid into. All power except for wind, which must be taken as it comes, must be bid into the pool. Bilateral contracts also exist. All supply is paid the same price through the pool, which is the highest price that clears. The National Electricity Code controls the by which the power is placed on the market.

Australia does not have a nodal pricing system. There are high variations in regional spot prices due to loss factors for transmission and capacity. Long periods of market separation, however, are infrequent.

ACCC sets prices for electricity transmission lines. The Minister for energy has review powers over certain ACCC decisions, and has suggested that the regulator's power be curtailed.