ELECTRICITY RESTRUCTURING:
A COMPARATIVE REVIEW

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March 27, 2003
This Version: March 2004
We are grateful for comments by Tom Adams, Don Dewees, Larry Ruff and Adonis Yatchew.
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I. Introduction

In many jurisdictions, one of the most controversial initiatives in economic deregulation and restructuring has been in markets for electricity. The three main components of the electricity market are generation, transmission and distribution. In the past, network effects and substantial construction and maintenance costs led many to consider these sectors to be natural monopolies. The operational and investment complementarities between generation and transmission were also believed to merit the integration of the sectors. As a result, many jurisdictions chose to vertically integrate these segments into a government or private monopoly. To prevent the abuse of monopoly power governments commonly imposed price controls and/or rate of return regulation.

Over the past two decades, long-running inefficiencies associated with these monopoly arrangements, specifically poor investment decisions (e.g., significant over-investment in nuclear power) and cross-subsidization practices have led many jurisdictions to re-evaluate the structure of their electricity markets. This motivation for restructuring involves the desire to shift the risk of investment from consumers/taxpayers to producers/investors. A number of other factors have contributed to this drive for reform. First, during the 1980s and 1990s, it became generally accepted by policy makers that competitive markets offered significant benefits over regulated monopolies. Second, technological change, such as combined cycle gas turbines, wind turbines and local generation (e.g. solar power), have created opportunities for small-scale electricity

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generation and competitive generation markets.\textsuperscript{5} Such innovations led to the average costs of some new plants being less than the average costs of some of the existing plants of incumbent utilities.\textsuperscript{6} In some cases, small-scale generation may also serve as a substitute for transmission facilities as generators can be sited to deliver electricity directly into a distribution system or be used for self-generation by a large consumer. Further advancing the viability of competitive generation are innovations reducing energy losses during transmission that have increased the distance at which generators are able to compete with each other (e.g. generators in British Columbia are able to export electricity to California).\textsuperscript{7}

The emergence of competitive electricity generation markets has created a new sector in the industry: retailing.\textsuperscript{8} The selling of electricity to end-users by retail intermediaries provides an opportunity for a competitive market.

Despite the development of small-scale generation, both the transmission and distribution sectors are still considered ‘natural’ monopolies because of large sunk costs and network externalities.\textsuperscript{9}

The expected gains from restructuring and deregulation are more efficient pricing and better-informed consumption and investment decisions.\textsuperscript{10} However, a number of issues make restructuring and deregulation of this market more complex than deregulation of other markets.

\textsuperscript{5} Michael Trebilcock and Michal Gal, “Market Power in Electricity Industry Restructuring,” \textit{World Competition}, 22(1), (1999), note 2, p. 125; White (1996), p. 213. Single and combined-cycle gas turbines allow power plants delivering 50 to 250 megawatts of electricity with lead times of 24 to 36 months. Wind turbines allow for smaller scale generation (e.g., 1.5 MW).
\textsuperscript{6} White (1996), p. 230. However, some small-scale generation, such as simple-cycle turbines and diesel generations are likely to have higher capital, operating and environmental costs than some traditional large-scale transmission-based facilities; also see Jonathan A. Lesser and Charles D. Feinstein, “Distributed Generation: Hype vs. Hope,” \textit{Public Utilities Fortnightly}, 140 (11), (June 2002), pp. 20-28.
\textsuperscript{7} Severin Borenstein and James Bushnell, \textit{Electricity Restructuring: Deregulation or Reregulation?}, University of California, Program on Workable Energy Regulation, PWP-074, (February 2000), p. 3.
\textsuperscript{10} Borenstein and Bushnell (2000), p. 6.
We identify the challenges facing a jurisdiction contemplating electricity market reform, review various transition mechanisms to address these challenges and examine the experiences of some jurisdictions that have undertaken reform.

II. Challenges to Transition

Numerous problems may occur when restructuring an electricity market. Primary concerns include: (1) pricing by incumbent generators, transmitters and distributors; (2) discriminatory network access by monopoly transmitters and distributors; (3) the inelasticity of electricity supply and demand at peak times; (4) the lack of real-time price notification and response by consumers; (5) the issue of stranded costs; and (6) political and consumer resistance to increases in retail prices. Moreover, there are a number of issues that complicate new entry in the generation sector: (1) the time required to get a new power plant online often takes years; (2) the financing required to construct a new power plant remains substantial despite technological advances; and (3) plant financing can be extremely risky in an environment of volatile prices. Further, because electricity cannot be stored efficiently, supply and demand must continuously be balanced at every moment in time, leading to potential generation and transmission coordination problems in a competitive marketplace. Failure to properly balance supply and demand will destabilize the entire transmission grid, harming all consumers in the form of service interruptions. The fragility of electricity systems was reflected dramatically in the massive power blackout in the northeastern U.S. and Ontario in August 2003.

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Because in the short-run both supply and demand inelasticity can simultaneously exist in electricity markets, small shifts in supply/demand can trigger extreme price movements, providing incentives and opportunities for generators to exercise market power either unilaterally or through collusion. Market power is typically exercised through withholding generation power from the market. There are two ways to withhold capacity: (1) economic withholding (i.e. demanding a higher price for generated electricity), or (2) physical withholding (i.e. not producing electricity). Physical withholding is the most common form of market power exercised in electricity markets. By physically withholding power, an electricity producer may be able to shift the supply curve into the vertical portion of the demand curve during a period of peak demand. Borenstein has noted that, during peak use hours, firms with a generation capacity share as low as six percent may be able to unilaterally exercise market power by withholding generation and increasing prices significantly above competitive levels on remaining output.\textsuperscript{15} This implies that the number of competitors necessary for effective competition in the electricity generation sector is higher than typically thought necessary in most markets. Where limited transmission capacity prevents imports from setting the price, a small share of regional market can be sufficient for the exercise of market power.

An extremely contentious issue in the United States, where utilities are predominantly investor-owned, revolves around the issue of “stranded” costs. Prior to deregulation, regulated investor-owned utilities providing electricity services made investment decisions in a non-competitive environment with a rate of return specified by the industry regulator. When a jurisdiction decides to deregulate, the incumbent utility’s revenues are no longer guaranteed and may decrease because of competitive pricing, creating the possibility of stranded costs.

The regulatory commitment would be met if, at the time of deregulation, a utility was compensated for the non-depreciated portion of its historical investment (i.e. the book value of its assets). The gap between the book value of a utility’s assets and the market value of its assets (or present value of earnings on the assets) in a restructured and deregulated market is referred to as the utility’s stranded cost. These stranded costs, largely comprised of U.S. utilities’ investments in nuclear power during the 1970s and 1980s, vary in estimates from tens of billions of dollars to hundreds of billions of dollars. In the absence of stranded cost recovery, the incumbent may not be able to afford the financing of its already incurred costs, potentially threatening the financial solvency of the firm and possibly compromising the future competitive structure of the industry. Alternatively, poorly designed recovery schemes can distort market prices, giving incumbents an advantage over new entrants or vice versa. It is important to note that stranded costs cannot be eliminated by restructuring and deregulation; these costs will be borne by some party or parties (e.g. consumers, creditors, shareholders, taxpayers) regardless of the policy chosen.

As a result of the concerns noted above, and recent restructuring failures, some industry commentators have concluded that competitive electricity markets are currently unattainable, arguing that vertically integrated regulated monopolies remain the best available delivery option for reliable and affordable electricity provision. This belief has spread rapidly in the United States since the disastrous restructuring efforts in California. As the maps below indicate there has been a dramatic change in the state of restructuring in the United States, with many states abandoning restructuring initiatives.

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17 Coyle (2002).
State Status of Restructuring as of February 2001

Source: http://www.eia.doe.gov/cneaf/electricity/page/fact_sheets/restructuring.html
Status of State Electric Industry Restructuring Activity
-- as of February 2003 --

Source: http://www.eia.doe.gov/cneaf/electricity/chg_str/regmap.html
III. Addressing the Challenges

While the challenges noted above are numerous and substantial there is no shortage of proposed remedies, many of which may give rise to new problems. A number of commentators have suggested methods that jurisdictions may follow when approaching market reform. The “standard” approach to restructuring and deregulating an electricity market includes the following elements: (1) privatizing state-owned firms; (2) asset divestiture by incumbents (3) vertical deintegration; (4) ensuring a competitive generation market by allowing new entry and fully deregulating generation prices (i.e., wholesale and retail prices; spot markets and forward markets); (5) unbundling electricity charges; (6) ensuring non-discriminatory access to transmission and distribution networks; (7) performance-based regulation for setting transmission and distribution rates; (8) retail competition; and (9) ensuring private investors that commercial and regulatory commitments will be respected.\(^{18}\)

1. Generation

The key issues with respect to generation restructuring are mitigating market power and ensuring sufficient capacity (i.e. new entry and investment).

Given Borenstein’s observation of the relatively small share of generation capacity needed to exercise market power, the division of pre-existing generation assets prior to market opening is a critical component to creating a competitive market. Numerous authors have recommended substantial horizontal divestiture of incumbent utilities’ generation facilities to

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foster effective competition. However, if deregulation involves the privatization of government assets significant horizontal separation would decrease the level of profits for future owners, decreasing the price buyers would be willing to pay for generation assets. On the other hand, minimal horizontal separation may discourage new entry into the generation market if the incumbent is able to pursue predatory or limit pricing strategies vis-à-vis new entrants. This creates the complex problem of a government being required to make a trade-off between long-run economic efficiency, the level of profits necessary to attract entry into the generation market, and the government’s own revenue maximization objectives. However, because the ultimate objective of deregulation is efficient and competitive markets substantial horizontal restructuring of the generation sector, especially in the presence of a government monopoly, is warranted most circumstances.

In curtailing the exercise of market power, a jurisdiction may contemplate establishing a maximum capacity share that a firm may own. For example, in Argentina, the law states that no firm can control more than ten percent of all generation capacity.

Once a jurisdiction has settled the initial market structure problem it must then turn to creating an environment in which generation capacity is continuously sufficient to meet demand. With respect to sufficient capacity, Dewees observes that “[t]he smoothest openings of competitive markets have coincided with excess supply, while the worst were those that opened with shortages.” Jaccard proposes that governments or consumers pay a premium to generators

21 Ibid.
23 Donald Dewees, Pricing and Environment in Electricity Restructuring, University of Toronto Law, Faculty of Law and Economics Workshop Series, (March 2002), p. 7.
to maintain a pre-specified reserve margin (e.g., 15 percent) to ensure sufficient capacity as well
as constrain price volatility in the event of an unexpected supply/demand shock,\textsuperscript{24} for example, a
capacity payment that increases as reserves falls and decreases as reserves grow.\textsuperscript{25} A capacity
reserve premium may be necessary to elicit such behaviour because peak generation units will
run infrequently.\textsuperscript{26}

An alternative instrument is a capacity reserve requirement. This mechanism requires “all
load-serving entities” (i.e., utilities and retailers) to have contracted sufficient capacity to satisfy
peak demand and hold a specific reserve amount. A capacity reserve requirement also requires
consumers to pay a premium for excess capacity. Stoft argues that while a capacity reserve
requirement has problems (i.e., regulators must be able to measure demand elasticity, and define
and confirm installed capacity) it is a direct way to address the issue of supply reliability.\textsuperscript{27}
Sweeney describes the potential framework for a capacity reserve requirement: “Before the
beginning of each month, each load-serving entity would be required to demonstrate to the
[independent system operator] that it has procured adequate capacity for the following month.
Those entities that had shortfalls would be assessed a substantial penalty.”\textsuperscript{28} A capacity reserve
requirement has the benefit of increasing the use of forward contracts; however, it too requires
consumers to pay a premium for the excess capacity.

However, Borenstein argues that government mandated excess capacity is likely to be
suboptimal, creating an inefficient setting differing little from the initial regulated marketplace.\textsuperscript{29}

\textsuperscript{24} Mark Jaccard, \textit{California Shorts a Circuit: Should Canadians Trust the Wiring Diagram?}, C.D. Howe Institute
\textsuperscript{25} Michael J. Trebilcock and Ron Daniels, “Electricity Restructuring: The Ontario Experience”, Canadian Business
\textsuperscript{26} Jaccard (2002), p. 15.
\textsuperscript{29} Borenstein (2002), p. 203.
For example, in England and Wales, there were concerns that generators abused the capacity payment system in order to maximize capacity payment revenue.\textsuperscript{30}

Yet, even though maintaining excess capacity raises the prices consumers must pay, requiring generators or suppliers to maintain a pre-specified reserve margin may be necessary to encourage generation investment if private sector actors do not believe the government can commit to restructuring and deregulation. Such mechanisms may be necessary to manage the transition to deregulated markets in the short-run, but can be phased-out over time as consumers and producers become accustomed to the dynamics and reliability requirements of the reformed market. The apparent lack of gaming opportunities associated with a capacity reserve requirement suggests that it is superior to capacity payments.

As to whether the financial risks associated with the generation market are likely to discourage new entry, White argues that forward contracts for electricity provision effectively overcomes this obstacle.\textsuperscript{31} By permitting long-term bilateral contracting, firms desiring to enter the generation market will have a secure future revenue stream, mitigating the sunk-cost problem and allowing firms to obtain project financing.\textsuperscript{32} It should be noted that an efficient forward market requires a properly functioning spot market.\textsuperscript{33} Borenstein notes that forward contracting prevents the exercise of market power because the firm has committed to selling a fixed amount of electricity at a fixed price, limiting its ability to withhold (both economically and physically) and benefit from efforts to raise prices in the spot market.\textsuperscript{34} Thus, forward contracting can result in a less volatile and more competitive spot market.\textsuperscript{35} Therefore, long-term forward contracting

\textsuperscript{30} Kwoka (1997).
\textsuperscript{31} White (1996), p. 216
\textsuperscript{32} Ibid.
\textsuperscript{33} Ibid., pp. 216-7.
\textsuperscript{35} Catherine Wolfram, \textit{Electricity Markets: Should the Rest of the World Adopt England and Wales Reforms?} University of California, Program on Workable Energy Regulation, PWP-069, (September 1999), p. 16.
enhances market entry and mitigates market power problems; a jurisdiction contemplating deregulation should ensure that it does not prohibit or raise the costs of long-term forward contracting when designing market rules.

While forward contracting has many benefits, it should be noted that claims by generators that forward contracting is necessary to attract private investment are not entirely compelling. Indeed, in some cases the argument may be an attempt to capitalize on a jurisdiction’s need for new generation coupled with the information asymmetries between electricity producers and the government regarding the realities of the industry. To illustrate, Rothwell and Gomez argue that forward contracts in electricity markets between private producers and consumers typically do not last more than a few years and that financiers consider other factors (e.g., collateral) when making lending decisions.\(^{36}\) Moreover, in many industries, such as automobiles, advanced technology, and natural resources, plants and facilities of substantial cost are built without any long-term contracts pre-selling the final product.\(^{37}\) However, it should be noted that capital markets lost confidence in the electricity sector following the California crisis in 2000 and 2001, and the collapse of Enron, increasing the need for private investors to pre-sell electricity prior to acquiring financing.

Given the short-run constraints on supply and demand elasticity some policy makers consider that price or rate of return regulation, typically imposed on the incumbent, to limit the abuse of market power may be necessary until a competitive environment emerges. However, there are significant drawbacks associated with such instruments that threaten to undermine the

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\(^{36}\) Geoffrey Rothwell and Tomas Gomez (Eds.), *Electricity Economics: Regulation and Deregulation*, (IEEE: 2003): “The price volatility of power markets is the rationale for both sellers and buyers to make long-term contracts to hedge against uncertainty. These contracts usually do not last more than a few years and they are rarely the basis on which financiers award construction loans for generation plants. More frequently, financiers back plants because the borrower (typically an established utility that can assume risk) can provide collateral. However, the expectation of future cash flows is currently the main market force driving generation expansion in competitive markets.” (p. 111)

\(^{37}\) The authors would like to thank Steven Stoft for this observation.
pursuit of competitive generation markets. For example, a price cap that is set “too low” will deter entry and possibly prevent incumbents from covering their own generation costs, causing further investment outflows. Alternatively, if the price cap is “too high,” market power can be exercised in the short-run. The use of these instruments may create uncertainty and discourage investment if investors believe the government cannot commit to a competitive price regime.\textsuperscript{38} Furthermore, investment may be discouraged because of the uncertainty regarding how prices will behave if, and when, price deregulation occurs.

\textbf{2. Transmission and Distribution}

The key issues with respect to restructuring transmission and distribution services are access, pricing and capacity expansion and maintenance.

The “standard” restructuring prescription effectively deals with the monopoly problems that may arise in the transmission and distribution sectors through mandated full or partial separation of transmission and distribution from generation and mandatory interconnection. Vertical separation eliminates the ability of transmission and distribution monopolies to exercise market power by engaging in activities such as favouring their own generation plants over those of competitors. However, some commentators criticize open-access requirements as inefficient and short sighted. For example, Crews argues that mandatory interconnection will result in regulators setting interconnection access prices lower than those attained by bargaining in a competitive market.\textsuperscript{39} As a result, such policy will distort incentives to invest in new generation facilities. Crews argues that suboptimal interconnection access pricing will bias investment towards generation feeding directly into the transmission grid while decreasing incentives to invest in micro-generation technologies that can be used for self- or distributed-generation,

\textsuperscript{38} Borenstein (2002), p. 208.
bypassing the transmission grid (i.e. mandatory interconnection discourages the development of
technologies that could overcome distribution and transmission monopolies in the future).40

Borenstein and Bushnell argue that expanding transmission capacity, increasing the
ability of a jurisdiction to import power and reduce grid congestion, should be an element of any
transition plan.41 Transmission expansion can increase the number of potential competitors in the
generation market in a time frame shorter than that required to construct new large-scale
generation facilities. However, increasing the capacity for electricity importation will redistribute
income from local suppliers to outside suppliers, likely leading to political opposition from
adversely affected generators.42 Additionally, dependence on electricity imports, and by
extension the expansion of transmission grid integration, has been criticized in the wake of the
power blackout of August 2003, with some jurisdictions desiring to become self-sufficient in
generation capacity.

It should be noted that a conflict between transmission and generation capacity expansion
arises as a result of deintegration. For example, Watts argues that “[w]ith regulated generation,
grid expansion decisions can be made in the context of generation plans. It is not clear, however,
how these decisions can made as sensibly in an environment in which generation plans may be
trade secrets and in which different grid enhancements will greatly favor different
competitors.”43 An alternative suggestion is to hand over operation of the grid to an independent
system operator (ISO) that would identify investment schemes that the owner(s) of the
transmission grid would be mandated to develop.44 According to Hunt “a transparent and stable

40 Ibid.
42 Ibid.
(May 2001), p. 22.
set of rules for identifying, evaluating, building, and charging for required new facilities that are necessary, feasible, and in the public good,” is required if centralized transmission planning is used.45 Partly as a result of this coordination problem, Kiesling argues that the efficiencies accruing from vertical integration should not be overlooked and that mandated divestiture may be inappropriate.46

There are a variety of pricing mechanisms available for the transmission sector: zonal, nodal and postage stamp pricing.47 In theory, zonal and nodal pricing (nodal pricing is also referred to as locational market pricing) involves setting prices that reflect the relative amount of capacity at a particular point (nodal), or region (zonal), of the transmission grid. Zonal and nodal prices “are continuously adjusted over time and are set for delivered energy, including both the price of energy and the price of transmission.”48 The difference between locational prices indicates the value of transmission.49 Such pricing creates signals for both efficient grid and generation capacity expansion.

Postage stamp pricing (the most common and only form of transmission pricing used by most jurisdictions) is a flat rate paid by all consumers. The charge is designed to pay for the fixed costs associated with maintaining the transmission grid, but supplies no investment signaling. When not used in conjunction with zonal or nodal pricing, postage stamp pricing requires that non-price methods (i.e., market rules) be used to manage transmission congestion problems. Locational market pricing (LMP), particularly nodal pricing (with a fixed transmission charge) is thought to be the optimal pricing mechanism. However, such a pricing mechanism

45 Hunt, p. 205.
46 See Lynne Kiesling, Getting Electricity Deregulation Right: How Other States and Nations Have Avoided California’s Mistakes, Reason Public Policy Institute, (April 2001).
48 Ibid., p. 105.
may be liable to monopoly abuse (e.g., a transmission monopoly may refrain from expanding grid capacity in order to create congestion and raise nodal prices), requiring some form of regulatory oversight. Additionally, depending on the size of the grid, such pricing instruments can be complicated to implement.\textsuperscript{50} Furthermore, political resistance from consumers experiencing increased energy prices may result from the adoption of a locational pricing regime.

Rate of return and performance-based regulation has been used to prevent transmission and distribution firms from setting monopoly prices. A typical form of performance-based regulation sets a base price that is expected to decrease, in real terms, over time as a result of productivity gains (the “X” factor) while allowing adjustments for input price inflation.\textsuperscript{51} Performance-based regulation prevents the charging of monopoly prices while regulatory lag maintains incentives to increase profits through cost reductions.\textsuperscript{52} However, such regulation may provide incentives to reduce service quality in order to increase profits, implying that compensation schemes need to incorporate other criteria.\textsuperscript{53} Moreover, if the “X” factor is set “too high” investment will be discouraged, while an X factor set “too low” will lead to higher consumer prices.\textsuperscript{54}

An alternative to performance-based pricing is rate of return regulation that specifies a maximum return on equity that the transmission or distributor may earn (i.e. the regulated monopoly pricing mechanism), plus recovery of necessary operating costs\textsuperscript{55} A fixed return on equity introduces the problem that a rate that is “too low” will result in under-investment, while a rate that is “too high” would result in over-investment.

\textsuperscript{50} Ibid., p. 106.
\textsuperscript{52} Ibid.
\textsuperscript{53} Ibid; Rothwell and Gomez (2003), p. 87
\textsuperscript{54} IEA (2001), p. 112.
\textsuperscript{55} Ibid., p. 110.
Given the high costs of congestion, lack of competition and the difficulties in eliciting efficient investment, governments or consumers may wish to pay a premium to the transmission monopoly to maintain a pre-specified grid capacity in high-use areas, as well as a pre-specified level of import capacity. The use of a premium or reserve requirement may alleviate the need to use the more complex (and efficient) locational pricing mechanisms (i.e. nodal and zonal pricing).

3. Demand-Side Restructuring

Borenstein and others argue that, in practice, deregulation programs have excessively focused on the supply-side and, given the short-run constraints on generation capacity, reform should include increasing demand responsiveness. Borenstein argues that real-time pricing is a necessary element to ration demand at peak-times to avoid supply shortages (caused by a lack of generation or transmission capacity). Time-of-use meters, measuring the consumption of all consumers (i.e., residential, commercial and industrial), represent the best method of making demand more responsive to price and should be a component of any transition plan.

Demand responsiveness to price fluctuations will lead to a more efficient use of electricity by consumers over time, alleviating the need for excess generation and transmission capacity to meet on-peak demand. Exposing consumers to real-time prices will increase the demand for products that conserve electricity, creating incentives for manufactures to develop

appliances and equipment that consume less electricity. Real-time pricing also discourages firms from exercising market power, through withholding supply at peak demand times, because consumers will respond to the higher prices by lowering consumption. Therefore, real-time pricing has the potential to lower both prices and price volatility. Such a pricing mechanism will reveal the differences in demand elasticity across locations, providing the signals necessary for the accurate level and location of generation and transmission investments.

Despite the availability of real-time metering technology, it is not widespread at the end-user level, except for large industrial and commercial customers. This can be attributed to residential consumers and governments presently having an extremely low tolerance for short-run price volatility, and for higher prices even if these are efficient. The primary cause of this resistance is that, in some jurisdictions (e.g. Ontario), retail prices were frozen for many years prior to restructuring initiatives combined with an apparent inability of citizens to understand the costs to them of artificially low electricity prices. However, the nature of electricity supply and demand suggests that at peak times a slight decrease in demand can significantly reduce prices. For example, during its electricity crisis California had to resort to rolling blackouts with a supply shortage of only 300 MW. Real time pricing may have prevented this from occurring. As an alternative to real-time pricing, some commentators suggest that time of day and seasonal price schedules, identifying three to four periods where prices would vary during the day.

The best way to achieve demand-side responsiveness is often thought to be through retail competition. With retail competition different retailers will offer different price packages to

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66 Kelly (2003), p. 19
consumers (e.g., fixed-price, seasonal prices, real-time pricing), depending on the customer’s tolerance for price volatility and expectations about future prices. However, Joskow argues that in the absence of real-time pricing or other value-added services (e.g., a consolidated electricity and telephone bill or offering ‘green’ power, such as solar and wind power) retail competition offers few benefits to residential customers (i.e., there is little consumer gain from switching from an incumbent to a retailer in the absence of real-time pricing). In fact, there is little evidence to suggest that competitive retailers offer real-time pricing or other value-added services.

Ultimately, all consumers, except perhaps the smallest users, should be offered the choice of having interval meters. All consumers should have choice regarding the manner in which they pay for their electricity use (e.g. real-time, fixed prices, block pricing), depending on their preferences. However, to avoid rate shocks early in the restructuring process, which may lead to a policy reversal regarding market reform, it may be prudent to incrementally introduce retail competition and retail price deregulation. For example, in contrast to residential consumers, industrial real-time pricing is likely to be feasible immediately because businesses can increase profits by scheduling electricity intensive operations to off-peak periods.

4. Stranded Costs

Sidak, along with others such as Baumol and Spulber, has argued that transition plans should contain provisions allowing privately owned incumbent utilities to recover stranded costs. Proponents of stranded cost recovery argue that incumbents “have undertaken the very

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large investments and contractual commitments in fulfillment of their various public service obligations and have accepted regulatory limitations on their allowable rates of return in exchange for the promise of a reasonable opportunity to recover their prudently incurred costs.\textsuperscript{70}

The authors claim that this “implicit regulatory contract” between regulated utilities and governments entitles the utility to stranded cost recovery, arguing that failure to do so is a violation of the Takings Clause of the Fifth Amendment of the U.S. Constitution that prohibits the taking of private property for public use without adequate compensation.\textsuperscript{71}

However, Williams argues that regulatory reform is primarily based on the notion that the existing regulatory regime resulted in inefficient investment.\textsuperscript{72} Furthermore, Williamson argues that Sidak and Spulber ignore the possibility that the previous regulatory regime had been “captured” and opportunistically exploited by the incumbent monopolist.\textsuperscript{73} Navarro argues that the best policy is “zero recovery,” but adds that because incumbent utilities are likely to disrupt the reform process in the absence of recovery, a 50 percent recovery is an acceptable compromise.\textsuperscript{74}

Others argue that utilities be given a “fair opportunity” (e.g. 5 years) to recoup stranded costs, but not be guaranteed full recovery.\textsuperscript{75} Brennan and Boyd contend that because stranded costs can be differentiated into costs that were mandated by regulators and those that the utility undertook voluntarily an appropriate compromise may be to allow the full recovery of mandated

\begin{thebibliography}{99}
\item[70] Ibid.
\item[71] Ibid.
\item[74] Navarro (1996).
\end{thebibliography}
costs. However, if regulatory capture has occurred, recovery of costs incurred by actions mandated by regulators may also be open to question. Williamson suggests making “compensation contingent on a legal review of prudential investment, […] reserved for unusual regulatory changes, of which deregulation is one.”

If it is decided that full or partial stranded cost recovery will occur there are several ways to allow recovery. The simplest method is requiring a vertically integrated utility to divest its generation assets with the proceeds from the sale being used to pay off stranded costs. However, expectations of competition will likely lower the present market value of an incumbent’s generation assets, implying that additional compensation may be necessary. To accomplish this a generally accepted recovery method is requiring all customers in the deregulated market, regardless of who they choose to purchase generation service from, to pay a fixed transition charge compensating incumbent utilities for stranded costs (i.e. a non-bypassable charge). Joskow argues that this method is appropriate if it is calculated such that the incumbent utility fully assumes the risks of avoidable costs. If this condition is met an incumbent utility will be able to recover its stranded costs even if it is unable to compete in the competitive generation market (i.e. the incumbent’s avoidable cost of generation is higher than the market price). Therefore, in theory, stranded cost recovery need not necessarily distort competition. However, it does imply that while the price of electricity generation may decrease following regulation, the

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79 Ibid.
80 Ibid.
absolute decrease in total electricity charges may be quite insignificant for years if a full stranded cost recovery program is initiated.\textsuperscript{81}

In practice, the analysis requires transition plans to carefully differentiate between sunk and avoidable costs, and unbundle the various cost components (transmission, distribution, generation, stranded cost, etc.) associated with electricity provision.\textsuperscript{82} Thus, a critical point is whether stranded costs can be measured with any degree of accuracy. There is no neat solution to the calculation problem because the future market values of electricity prices and generation assets may vary significantly over the years allocated to stranded cost recovery.\textsuperscript{83} Recovery charges may be calculated “upfront” by estimating the net present value of stranded costs at the time of transition and the book value of assets. If the upfront method of calculation is used it is highly likely that recovery charges will likely be either “too high” or “too low” depending on how the market changes over time (i.e., the market outcomes that occur following deregulation will not match expectations).\textsuperscript{84} Alternatively, recovery charges could be calculated on an ongoing basis with recovery charges based on realized market values (e.g., revenues and asset prices) over time.\textsuperscript{85} The obvious problem with ongoing stranded cost recovery is that regulatory lag may allow incumbents to behave opportunistically.

Also complicating matters is that incumbents will seek to overstate stranded costs and prevent the proper unbundling of avoidable and sunk costs. If successful, incumbents may be able to use recovery charges to cross-subsidize inefficient generation facilities and deter entry (i.e. engage in predatory pricing), regardless of the recovery method used.\textsuperscript{86} Therefore, the

\begin{flushleft}
\textsuperscript{81} White (1996), p. 244.
\textsuperscript{82} Joskow (1996).
\textsuperscript{83} Ibid.
\textsuperscript{84} Ibid.
\textsuperscript{85} Ibid.
\textsuperscript{86} White (1996), p. 244.
\end{flushleft}
practical difficulties in designing a stranded cost recovery scheme for investor-owned utilities appears to suggest that partial recovery is preferable to full recovery.

Thus, the claim and ability to implement full stranded cost recovery is dubious at best. However, given that denial of stranded cost recovery will lead to significant political resistance by incumbents to reform, it is likely that policymakers will permit at least partial recovery. Stranded cost recovery also may be necessary to enhance the credibility of the government’s deregulation policy.

When an incumbent utility is publicly owned the stranded cost problem is less complex. The costs are typically recovered through the privatization of assets, and if further recovery is required it can be paid for through a non-bypassable transition charge or from general tax revenues. Thus, the stranded cost problem is less relevant when the utility is publicly owned.

The results of restructuring in a number of jurisdictions will now be examined.

IV. Empirical Evidence

1. Ontario

Ontario represents an unsuccessful attempt by a jurisdiction to move from a regulated integrated government monopoly to competitive markets. The evidence indicates that the lack of commitment towards restructuring (i.e., to privatize and restructure the generation market) exhibited by the provincial government contributed to the tight supply-demand situation and volatile prices experienced in the summer of 2002. A reduction in domestic generation capacity, an increasing reliance on imports, limited import capacity, and extreme temperatures all contributed to higher prices. These developments did not suddenly emerge in the summer of 2002; most were apparent years before Ontario’s market opened to competition in May of 2002.

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Prior to reform, Ontario had a vertically integrated government-owned monopoly, Ontario Hydro, responsible for electricity generation and transmission. The electricity generated and transported by Ontario Hydro was purchased and distributed by about 300 local municipally-owned utility companies to consumers. Consumers were charged a fixed price per kilowatt hour (kWh) that bundled together generation, transmission and distribution costs. In response to mounting debt problems facing Ontario Hydro through the 1990s, the government of Ontario embarked upon a restructuring program beginning in the mid-1990s.

In 1999, Ontario Hydro had a provincially guaranteed debt of approximately $38.1 billion (about a third of total provincial indebtedness). However, the value of Ontario Hydro’s assets was only $18.7 billion, leaving a “stranded” debt of $19.4 billion. Through the 1990s, roughly 35 percent of the Ontario Hydro’s electricity revenue went towards paying debt interest. Much of this debt was incurred through over-expansion and major cost-overruns in the construction of nuclear generation facilities. For example, the Darlington nuclear station was completed between the years of 1989 and 1994; construction was originally to be completed in 1983. The final cost of the plant was $14.4 billion, roughly 3.7 times more than the inflation adjusted expected cost. Additionally, in 1998, eight of Ontario Hydro’s 20 nuclear plants were out of service due to reliability and/or safety problems. As a result of these problems the price of electricity in

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Ontario rose by 30 percent in the early 1990s before the government froze the price of electricity for the balance of the decade.\textsuperscript{93}

The provincial government appointed a Task Force in 1995 to explore the possibilities for reforming the province’s electricity market. In 1996, the Task Force’s report (referred to as the MacDonald Report) made various recommendations for realizing a more market-based electricity industry in the province, including the possibility of privatization and the break-up of Ontario Hydro.\textsuperscript{94} Following the MacDonald Report a government White Paper was released in 1997, proposing full wholesale and retail competition by 2000 and the division of Ontario Hydro into two state-owned enterprises—Hydro One (transmission) and Ontario Power Generation (generation), but no further structural changes.\textsuperscript{95} The White Paper led to the creation of the Market Design Committee (MDC) in 1998.

The MDC was responsible for designing and recommending rules for wholesale and retail competition in the province’s electricity markets. In 1998, the provincial government formally set out the framework for the reformed electricity market in the \textit{Electricity Act}.\textsuperscript{96} The government vertically deintegrated Ontario Hydro into its transmission and generation components. In 1999, these new firms, Hydro One and Ontario Power Generation (OPG), began their operations but remained fully state-owned.

The government has two agencies to oversee the electricity market: the Ontario Energy Board (OEB) and the Independent Market Operator (IMO). The IMO controls the bulk electricity system and operates the wholesale spot market to ensure system reliability; its independent

\textsuperscript{93} Ontario, \textit{Direction for Change: Charting a Course for Competitive Electricity and Jobs in Ontario}, (November 1997).

\textsuperscript{94} Ontario, Advisory Committee on Competition in Ontario’s Electricity System, \textit{A Framework for Competition}, (1996).

\textsuperscript{95} Ontario (1997).

\textsuperscript{96} \textit{Electricity Act}, 1998, S.O. 1998, c. 15, Sch. A.
Market Surveillance Panel monitors market power abuses. The primary purpose of the OEB is to regulate the monopoly segments of the electricity market (i.e., transmission and distribution). The OEB approves electricity transmission and distribution rates. The OEB was to implement a performance-based regulation regime for setting distribution rates. The cost of transmission continues to be recovered exclusively through a postage stamp transmission charge, although the MDC recommended that some form of zonal or nodal pricing be progressively implemented.

To prevent OPG from using its dominant position to exercise market power, the Market Design Committee recommended that OPG enter a Market Power Mitigation Agreement (MPMA) with the government. The MPMA mandated that OPG be subject to a wholesale price cap. OPG must pay a rebate to consumers on 90 percent of its domestic sales where the wholesale price exceeds 3.8 cents per kWh. The MPMA also required OPG to divest 65% of its price-setting generating units within the first three-and-a-half years after market opening, and 65% of its core or base-load facilities within ten years of market opening. The OPG rebate does not apply to divested capacity. In order to prevent monopolistic pricing and access restrictions by Hydro One and local distributors the Electricity Act states that “[a] transmitter or distributor shall provide generators, retailers and consumers with non-discriminatory access to its transmission or distribution systems in Ontario.” Additionally, Hydro One undertook to make best-efforts to increase inter-tie capacity by 50 percent within three years of market opening.

In complying with the MPMA, OPG leased its Bruce nuclear power plants to British Energy/Bruce Power in May 2001 (following the insolvency of British Energy the Bruce plants

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97 The OEB licenses all electricity market participants including generators, transmitters, distributors, wholesalers, retailers and the IMO. The Board’s approval is also required for amalgamations, mergers, acquisitions and divestitures of distributors, and transmission line construction.
98 Daniels and Trebilcock, p. 170.
100 Ibid., p. 26. Marginal units are the units that are brought on-and off-line as needed to meet peak load capacity, whereas core or base load units are the units that are the main, steady source of power.
were transferred to a new owner in February 2003)\textsuperscript{102} and sold its price-setting Mississagi hydro-electric plants to Brascan in March 2002. During the summer of 2002, the province blocked the sale of two OPG coal-fired generating plants in Northern Ontario allegedly because the sale price was too low and the buyer refused to convert the plants to natural gas fire facilities.\textsuperscript{103} OPG currently controls approximately 70 to 75 percent of the province’s generation capacity.

In December 2001, the province announced that it intended to sell Hydro One through an initial public offering (IPO). Two unions challenged the privatization of Hydro One, alleging that the\textit{Electricity Act} did not authorize the provincial government to sell the firm’s assets.\textsuperscript{104} On April 19, 2002 the courts ruled in favour of the union’s challenge\textsuperscript{105}

In May 2002, the Ministry of the Environment and Energy initiated public consultations regarding future restructuring of Hydro One;\textsuperscript{106} the province also announced that privatization was “off the table for [the] immediate time being,” and that a decision would be made following a public consultation process.\textsuperscript{107} In June 2002, the province announced that it would sell only a minority stake (49 percent) in the company and would retain management authority over the day-to-day operations of the firm.\textsuperscript{108} On June 27, 2002 the government enacted the\textit{Reliable Energy and Consumer Protection Act} which gave the province the authority to sell Hydro One.\textsuperscript{109}

The\textit{Reliable Energy and Consumer Protection Act} also allowed the province to fire the board of directors of Hydro One. This action was motivated by accusations that the firm’s board

\textsuperscript{102} The new group is a consortium including the Ontario Municipal Employees Retirement System, the Power Workers’ Union, the Society of Energy Professionals, TransCanada Pipelines, and Cameco.
of directors had agreed to award excessive compensation packages to senior management. The
board resigned en masse rather than being fired by the province. In July 2002, the CEO of Hydro
One was fired for excessive spending by an interim board of directors appointed by the province.
In August 2002, the government appointed a new permanent board of directors for the
corporation. On January 20, 2003 the province announced that it would retain 100 percent
ownership of Hydro One.110

In April 2002, the month before market opening, the IMO’s 10-Year Outlook (from 2003
to 2012) stated that “[b]ased on existing and proposed facilities, Ontario is expected to have
reliable supply of electricity for the ten-year period under a wide variety of conditions.”111

Ontario’s electricity market opened to both wholesale and retail price competition on
May 1, 2002 (market opening was originally scheduled for November 2000, but delayed to May
2001 and later May 2002 to ensure system reliability and to allow thorough testing of the
hardware and software acquired by wholesale market participants, service providers and retailers
to implement the wholesale and retail market design). In the open market wholesale electricity
prices vary every five minutes in response to changing levels of demand and supply.
Participation in the wholesale market is voluntary; consumers may directly enter into bilateral
physical or financial contracts with wholesale sellers and generators. Under retail competition
consumers were free to enter into fixed-price contracts with retail intermediaries. A consumer
not establishing a relationship with a retailer purchased electricity through their local distribution
utility, paying the average hourly spot market price. Almost one million of the province’s

111 IMO, 10-Year Outlook: An Assessment of the Adequacy of Generation and Transmission Facilities to Meet
estimated 4.4 million electricity customers entered into fixed-price contracts with retail intermediaries.\textsuperscript{112}

When the market opened the average hourly wholesale price was 3.01 cents per kWh (all prices stated are the weighted average for the month) in May and 3.71 for June, both below OPG’s 3.8 cent wholesale price cap. Prices began to increase as the summer progressed. In July the average hourly energy price (AHEP) was 6.2 cents. On July 2, 2002 the IMO issued a Power Warning stating that “hot weather and increased air conditioning load continue to strain power supplies. Homeowners, industries and businesses are being asked to immediately reduce their electricity consumption.”\textsuperscript{113} On July 29, 2002 the IMO issued a Power Advisory asking consumers to reduce electricity consumption.\textsuperscript{114}

By August 2002 prices reached 6.94 cents per kWh. Power Advisories were issued by the IMO on August 12 and 14.\textsuperscript{115} The summer peak occurred in September 2002 with the AHEP being 8.31 cents per kWh. The highest hourly price recorded was $1.03 per kWh ($1028.42 per MWh) during hour 14 of September 3.\textsuperscript{116} A Power Advisory was issued by the IMO on September 9, followed by a Power Warning “in response to continuing strains on the electricity system as a result of unusually hot weather and high humidity,” on September 10.\textsuperscript{117}

In October 2002, the IMO stated that “[t]here is a serious shortage of generation capacity to meet Ontario’s growing demand for electricity. If steps are not taken to address this situation,

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\textsuperscript{112}“Ontario government moves killed energy retailing, say executives,” \textit{Canadian Press Newswire}, (November 13, 2002). It should be noted that consumers appeared to lack information about how to compare their prior bundled electricity charges with the unbundled rates following deregulation. As a result, some consumers signed retail contracts before the market opened to purchase unbundled electricity at nearly 6 cents per kWh, mistaking the energy price for the bundled rate.
\textsuperscript{113} IMO website: \texttt{www.theimo.com}: “Power Warnings are issued by the IMO when supplies of power may not meet demand. Current system conditions mean the IMO may need to take protective actions and reduce demand including, but not necessarily limited to, voltage reductions.”
\textsuperscript{114} Ibid. “The IMO issues a Power Advisory when supplies of power, supplemented by imports, are forecast to be adequate, but the expected high demand will put a strain on the electricity system.”
\textsuperscript{115} Ibid.
\textsuperscript{116} Ibid.
\textsuperscript{117} Ibid.
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Ontario could face even more serious reliability problems next summer, leading to the possibility of supply interruptions and continued upward pressure on prices during periods of peak demand.”

The average price of electricity in October was 5.09 cents per kWh.

On November 11, 2002, the province announced its intentions to rebate consumers for the high prices of the summer, freeze retail prices and directed local utilities not to cut off service to customers who could not afford to pay their electricity bill. The average price of electricity in November was 5.12 cents per kWh.

In response to mounting criticism of the high summer electricity prices the *Electricity Pricing, Conservation and Supply Act, 2002* was enacted on December 9, 2002. The Act lowered and froze the retail price of electricity for low volume consumers (i.e. those using less than 150,000 kWh/year, such as families, small businesses, and farmers) and other designated consumers (i.e. municipalities, universities and colleges, public and private schools, hospitals and registered charities) at 4.3 cents per kWh, and includes those who signed fixed-price contracts with retailers. The freeze covers approximately half of the province’s total electricity consumption.

The 4.3 cents per kWh rate was made retroactive to market opening, refunding any amount over 4.3 cents that a consumer had already paid. All energy rates (i.e. transmission, distribution, wholesale market charge, and customer charge) were also frozen or capped. Any changes to transmission or distribution rates will require the written approval of the Minister of Energy.

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119 “Eves promises legislation to cap cost of hydro on Dec. 1 and provide rebates,” *Canadian Press Newswire*, (November 11, 2002).


Energy. The wholesale market and customer charges are under review. Only wholesale prices remain determined by market forces.

On March 21, 2003, the province announced that it was extending the frozen retail price to consumers using less than 250,000 kWh/year (approximately a further 7,000 consumers). The average price was 8.48 cents per kWh in March. In April 2003, the average price was 6.16 cent per kWh. The average price for the first year of the open wholesale market was 6.2 cents per kWh. The first twelve months of the price freeze required the Ontario Electricity Financial Corporation, which has its debt guaranteed by Ontario taxpayers, to finance approximately $730 million of difference between wholesale and retail electricity rates; OPG covered the remainder under its rebate obligations.

The Market Surveillance Panel (MSP) of the IMO conducted an analysis of the Ontario wholesale market for the May through August 2002 period to determine whether generators had abused market power during the summer of 2002. After examining almost all high-priced hours (all hours where the price exceeded $200/MWh) the MSP came to the conclusion that there was no evidence that abuse of market power had occurred.

The MSP concluded that the supply-demand imbalance during the summer was caused by “increased demand, a nuclear outage, deratings on fossil-fired generators due to environmental limits, and less hydroelectric energy available.” The increased demand (the peak demand was 25, 414 MW at hour 14 of August 13, 2003) and diminished hydroelectric capacity were primarily the result of significantly above-average summer temperatures. The high temperatures increased the demand for electricity through the use of air-conditioners and lessened the available of water necessary for hydroelectric generation. From 1984 to 2001 the average annual

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125 IMO, (October 2002b), p. 22.
growth of primary energy demand in Ontario was 1.6 percent.\textsuperscript{126} During the first year of the open market Ontario experienced a demand increase of 5.5 percent.\textsuperscript{127}

A large contributor to the supply deficiency was a substantial amount of nuclear power generation being taken offline between 1995 and 1998, with little new generation capacity built. The nuclear capacity removed from service was comprised of the 2060 MW of the Pickering Nuclear Power Station-A (Pickering) and the 3300 MW of the Bruce Nuclear Power Station-A (Bruce). In October 2002, the IMO reported that “the percentage by which total available capacity exceeds the summer peak demand for energy—has fallen from 19.2% in 1996 to -1.5% in 2002.”\textsuperscript{128}

In late 1998, Ontario Hydro announced plans to investigate the restart of the Pickering units for the winter of 2000/2001. The restart experienced numerous delays and substantial cost overruns, apparently due to safety and technical issues. The first Pickering unit to restart did not begin producing electricity until August 2003, returning to commercial service in September 2003. The numerous delays and cost overruns led the provincial government to announce in November 2002 that it would establish an inquiry into the restart.\textsuperscript{129} In 1997, the restart of all four Pickering units was estimated to cost $780 million with the first unit returning to service in June 2000.\textsuperscript{130} The Pickering Review Panel found that if the Pickering restart continues returning all units would cost an estimated $3 to $4 billion, and that the last unit would be restarted between October 2006 and August 2008.\textsuperscript{131} The cost of constructing the entire Pickering A station in 1971, adjusted for inflation, was approximately $3.2 billion.\textsuperscript{132} The findings of the

\textsuperscript{126} IMO, \textit{Ontario Demand Forecast from January 2003 to December 2012}, (April 2002).
\textsuperscript{127} IMO (June 2003), p. 3.
\textsuperscript{128} IMO, (October 2002b), p. 132.
\textsuperscript{129} “Energy minister to debt raters: ‘Wait until the dust has settled’,” \textit{Toronto Star}, (November 14, 2002), p. D1.
\textsuperscript{131} Ibid.
Review Panel resulted in the provincial government accepting the resignations of OPG’s chairman, CEO, chief operating officer and board of directors. As in the case of Hydro One in 2002, the government appointed a new interim board of directors.

The IMO made emergency purchases of imported energy 38 times during the summer to maintain system reliability.133 Imports have been required to balance supply and demand during the summer for each year since 1997.134 The peak amount imported was 4273 MW during hour 14 of September 20, 2002.135 The large amount of imports strained transmission inter-ties with other jurisdictions. The province’s inter-ties with Manitoba, Quebec, New York, Minnesota and Michigan all experienced varying degrees of congestion during the summer.136 During some periods the province was importing the maximum amount of electricity (roughly 4000 MW) that the transmission system could physically accommodate.

Some consumers in the province reduced demand during the higher prices of the summer of 2002. Ontario has 90 industrial consumers that comprise approximately 15 percent of demand that are directly connected to the transmission grid and have interval meters that measure and report hourly consumption, allowing the user to be billed at the actual hourly spot price.137 The IMO estimates that a further 20 percent of total demand is comprised of industrial consumers not directly connected to the grid but possessing interval meters.138 According to the IMO, these interval meter consumers (representing roughly 35 percent of total consumption) reduced consumption in response to the rising prices of the summer, helping maintain system reliability.139 The MSP conducted an analysis of the consumption patterns of 18 of the 90 large

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134 Ibid., p. 131.
135 IMO.
136 Ibid., p.104.
137 IMO, (October 2002b), p. 17.
138 Ibid., p. 18.
139 IMO, 18-Month Outlook, (January 2003), p. ii.
consumers, finding that by shifting from peak to off-peak hours these consumers reduced their electricity bill by an average of $8/MWh from May 2002 through December 2002.\textsuperscript{140} Had these 18 customers faced the $43/MWh price freeze their demand for electricity would have been 200-300 MW higher during some peak-hours of the summer.\textsuperscript{141}

The MSP also conducted an analysis of the Ontario wholesale market for the September 2002 through January 2003 period.\textsuperscript{142} Again, no evidence of abused market power was found. The reasons for increasing prices over the period of study were virtually identical to those identified in the MSP’s first report (i.e. abnormal weather, import constraints, tight supply, etc.).

With the reduction of domestic capacity and increasing reliance on imports it would seem that profitable opportunities for private sector investment in generation existed in Ontario leading up to market opening. However, little private investment in electricity generation occurred. Only two new private generation projects (about 620 MW) became operational during the first year of the open market.

The delay in market opening and uncertainty over the final rules governing the market have been claimed to be factors contributing to the failure of the province to attract private investment. Specifically, if market opening had been able to occur in 2000 as originally planned, the crises of 2002 may have been partly avoided. The delay was costly because capital markets lost confidence in the electricity sector following the California crisis in the summer of 2000 and 2001 and the collapse of Enron during 2001 and 2002. As a result, investors who may have invested in generation capacity in 2000 came to view the North American electricity market as

\textsuperscript{141} Ibid., p. 105, 111.
\textsuperscript{142} Ibid.
too risky, and were no longer interested in raising or able to raise sufficient capital for new generation capacity when the Ontario market opened.

However, conditions within Ontario prior to the California crisis contributed to a lack of private investment. During 1998 and 1999, the private sector expressed a reluctance to invest in Ontario’s electricity sector because of continued OPG ownership and control of generation assets and prolonged divestiture timetable.\(^{143}\) In 2000, OPG owned and controlled approximately 90 percent of the province’s generation capacity. The provincial government did little to allay investor concern regarding OPG dominance. In fact, the provincial government sometimes contributed to undermining investor confidence. For example, the announcement of the Pickering nuclear units restart (i.e., increasing OPG’s generation capacity) in 1998 discouraged private investment. Additionally, in 2000, the province placed a temporary freeze on the sale of OPG’s coal-fired generation plants, stating the need for environmental safeguards to be in place prior to privatization.\(^{144}\)

The continued ownership and control of generation assets by OPG resulted in a large proportion of electricity sold in the province being subject to the MPMA rebate, reducing the incentives for consumers to enter into forward contracts with private generators. The lack of interest in forward contracts was evidenced by about 60 to 70 percent of electricity being purchased in the Ontario spot market during the first year of the open market.

Lastly, for technical reasons, accepted imports are scheduled one hour in advance of delivery, and cannot be dispatched on a five-minute basis as domestic generators can. The IMO does not use import prices to calculate Ontario’s wholesale price. However, if an import is accepted, the importer is guaranteed the offer price in cases where the Ontario market clearing


price is below it. The guaranteed-payment system was implemented to improve reliability. However, when Ontario demand is very high the guaranteed payment can create situations where it is more profitable to sell electricity to the Ontario market from outside than inside the province. For example, on one occasion in July 2002, out-of-province generators received $2 per kWh for electricity while Ontario generators were receiving 47 cents per kWh.145

As a result of decisions by the new provincial government, Ontario consumers will shortly begin to pay higher government-administered electricity prices. Beginning April 1, 2004, users covered by the 4.3 cent price freeze will pay 4.7 cents per kWh for the first 750 kWh of electricity consumed per month. For use above that level, consumers will pay 5.5 cents per kWh. The interim rate regime will prevail until the Ontario Energy Board develops a new electricity pricing plan by May 1, 2005.

2. California146

According to Sweeney “California’s political leadership failed in 2000 to respond effectively to the challenge of tight electricity markets, mismanaged the electricity crisis in 2001, and thereby saddled the state with heavy long-term, electricity related financial obligations.”147 Limitations on the ability of incumbent utilities to enter into forward contracts and a lack of political resolve to pass higher and economically justified electricity prices on to consumers played a pivotal role in the failure of restructuring and deregulation in California. Given the

actions of the state government one may be able to argue that California’s supply situation would have been better in the absence of restructuring.

The process of restructuring in California began over 1993 and 1994 when the state’s Public Utilities Commission (PUC) began developing proposals for a deregulated electricity market. One of the motivations for reform was that California’s electricity rates were the tenth highest in the country. The state was served by three vertically integrated investor-owned utility (IOUs) companies: San Diego Gas & Electric (SDG&E), Pacific Gas & Electric (PG&E) and Southern California Edison (SCE). When the PUC first began examining deregulatory proposals the combined market value of the incumbent utilities was over US$30 billion; however, as the state further developed its deregulatory plans the market value of the utilities fell by more than US$12 billion. The decrease in value suggests that investors did not expect stranded costs to be recovered following restructuring. This significant drop in value led incumbent utilities to lobby for stranded cost recovery policies to be adopted. The utilities were permitted to levy a Competition Transition Charge (CTC) per kWh on retail customers to recover stranded costs.

In January 1996, following more than a year of public debate, the CPUC announced that significant restructuring of the state’s electricity market would take place. The utilities would continue to own the transmission grid but were required to hand over control of the system to an independent system operator.

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151 Ibid.
With respect to grid access, in 1992, the U.S. Congress passed the *Energy Policy Act*, while in 1996 FERC issued Order 888 requiring open access to transmission grids. The incumbent utilities were required to divest at least 50 percent of their generation capacity and sell and repurchase all their remaining self-generated power in day-ahead and real-time spot markets through the government created, non-profit Power Exchange (PX). The PX operated as a uniform-price auction. Incumbents were mandated to sell and repurchase self-generated electricity through the PX to prevent self-dealing. Generation assets were concentrated among seven firms. The IOUs were also prohibited from participating in forward markets. Generators would bid their power into the pool, and the highest price (the system marginal price) became the uniform market-clearing price. Non-IOU generators and suppliers could voluntarily participate in the pool and engage in forward contracting.

The restructuring rules mandated that a utility’s retail rates for small and residential customers would be frozen at 10 percent below 1996 rates until a utility had recovered its stranded costs or March 2002, whichever came first. The rate was frozen to allow the IOUs to recover stranded costs as it was believed that generation prices would decline significantly with competition. The CTC was the difference between the price a utility purchased electricity from the Power Exchange and the frozen retail rate (i.e. the CTC was a variable rather than a fixed charge). In the summer of 1999, San Diego Gas & Electric (SDG&E) was able to complete its stranded cost recovery and free itself of the price cap; it would be the only utility to recover its stranded costs.

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153 Ibid.
158 Ibid. p. 19.
Prices averaged roughly US$33/MWh for the first two years (1998-1999) of the restructured market.\(^{160}\) This stability in prices was helped by a near record cool summer in 1999.\(^{161}\) However, from 1993 to 1999 the demand for electricity in the state increased by 18 percent while very little new generation capacity had been built.\(^{162}\) A primary reason cited for the lack of new generation construction were strict environment regulations that created significant delays in the permitting and siting process necessary to develop new generation.\(^{163}\) The lack of new generation would loom large when the California experiment faced a crisis in the summer of 2000.

The near record hot summer of 2000 not only increased the demand for electricity, but also reduced the capacity to produce hydroelectric power because of the extremely dry conditions not only in California but in neighbouring states.\(^{164}\) This situation exacerbated the price increases during the summer. From June through August 2000, the average wholesale spot price reached US$125 per MWh. On June 14, 2000, rolling blackouts affecting 97,000 SDG&E customers in San Francisco occurred. In September 2000, in response to consumer complaints of high prices, the CPUC recapped the rates of SDG&E (the utility had been passing wholesale price increases on to consumers). It is important to note that the short experiment of deregulated prices to SDG&E customers suggests that residential consumers reduce consumption when faced with higher prices.\(^{165}\)

\(^{162}\) Ibid., p. 16.
\(^{163}\) Yuffee (2001), p. 68.
In contrast to SDG&E, both SCE and PG&E collected negative CTCs because the PX price vastly exceeded the frozen retail rate.\textsuperscript{166} SCE and PG&E claimed that they lost US$11 billion because of the difference between retail and wholesale prices.\textsuperscript{167} As the financial outlook of the utilities deteriorated out-of-state generators refused to sell electricity to the state while in-state generators exported power, increasing electricity prices. This led to continued power shortages through 2000 and 2001. On December 7, 2000 the ISO declared a Stage 3 power alert, indicating power reserves had fallen below three percent. On December 13, in an attempt to avoid further blackouts, U.S. Energy Secretary Bill Richardson issued an emergency order for out-of-state suppliers to sell electricity to California. Additionally, in response to SCE and PG&E requests for retail price increases, the CPUC approved increases in retail rates in early 2001.

From January 17-18, 2001 rolling blackouts affecting hundreds of thousands of consumers in northern and central California occurred. From March 19-20 state wide rolling blackouts affecting over 1.5 million consumers occurred when a large number of the state’s power generators unexpectedly closed. Additionally, despite billions of dollars of electricity purchases by the state and the CPUC approval of a 40 percent rate increase, PG&E filed for bankruptcy on April 6, 2001, citing debts of US$8.9 billion.

During most of the crisis the CPUC refused to allow or severely limited the ability of the distribution utilities from entering into forward contracts. Many commentators believe that this component of the restructured market enabled generators to charge supra-competitive prices at peak demand times.\textsuperscript{168} Joskow and Kahn argue that unilateral physical withholding of generation

\textsuperscript{166} Sioshansi (2001), p. 738.
\textsuperscript{167} Ibid., p. 738.
occurred in California, citing large gaps between the maximum possible levels of generation and the actual levels observed from in-state generators.\textsuperscript{169} Others have suggested that the uniform-price auction may have allowed generators to exercise market power by withholding marginal units in order to be able to charge a higher marginal system price for all of their remaining units.\textsuperscript{170} It is also claimed that generators engaged in economic withholding that was made possible by the ISO being obligated to purchase emergency power to avoid outages regardless of the price.\textsuperscript{171} Borenstein, Bushnell, and Wolak estimate that the exercise of market power accounted for 59 percent of the price increase during the summer of 2000.\textsuperscript{172}

The IOU retail price freeze coupled with sharply raising wholesale prices meant consumers had no incentive to switch from their incumbent provider. Even though retail competition was permitted, few consumers, except for large commercial and industrial users, switched from their incumbent utility to an alternative electricity service provider.\textsuperscript{173} Consumers decided not to switch providers despite the presence of approximately 300 firms offering electricity supply. Due to insufficient demand most were forced to exit the market.\textsuperscript{174} Retail competition was suspended by the CPUC in September 2001.

The state entered into numerous long-term fixed price forward contracts near the end of the open market experiment. Interestingly, as the state entered into billions of dollars of forward contracts electricity prices began to decrease (the price decrease has also been attributed to a steep fall in natural gas prices),\textsuperscript{175} suggesting that forward contracting reduces future revenue uncertainty, contributing to more stable and lower spot prices. However, Sweeney estimates that

\begin{itemize}
\item [\textsuperscript{170}] Crow (2001), p. 20.
\item [\textsuperscript{171}] Ibid, pp. 20-1.
\item [\textsuperscript{172}] Borenstein, Bushnell, and Wolak (2002).
\item [\textsuperscript{173}] Sioshansi (2001), p. 736.
\item [\textsuperscript{174}] Ibid., p. 735.
\item [\textsuperscript{175}] Jurewitz (2002), p. 24-5.
\end{itemize}
the state government entered into approximately US$40 billion worth of power contracts that are likely to be worth US$20 billion, highlighting the perils of jurisdictions entering into such agreements during a crisis. Additionally, in order to prevent future capacity shortages, the state created the California Consumer Power and Conservation Financing Authority (Authority). The Authority’s mandate is to construct state-owned “peaker” plants to ensure that the state continuously has a 15 percent generation reserve capacity.

3. United Kingdom

The United Kingdom represents a relatively successful restructuring effort. Deregulation was primarily motivated by an ideological preference for less government involvement in the economy by the Thatcher government. Of note is that in 1989, the government increased the retail prices paid by small industrial users and residential consumers. Additionally, prior to restructuring, the electricity industry was used to subsidize the country’s coal industry through requiring utilities to purchase fixed amounts of British produced coal at non-competitive prices. These factors made price reductions following privatization and deregulation easier to achieve, enhancing the government’s ability to commit to the restructuring program. Prior to deregulation and restructuring, electricity generation and transmission in England and Wales was the responsibility of a state monopoly known as the Central Electricity Generating Board (CEGB). The distribution of electricity was carried out by 12 government owned and operated regional distribution boards in England and Wales.

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Deregulation and restructuring began in earnest with the *Electricity Act of 1989*. The new *Act of 1989* vertically deintegrated and privatized the CEGB into two generation companies and a transmission firm. The distribution network was restructured into 12 privatized regional electricity companies (RECs). Transmission and distribution prices are controlled through performance based RPI-X regulation (RPI is the retail price index and X the productivity factor). RECs were permitted to provide generation services as long as their generation capacity comprises no more than 15 percent of their peak demand. The RECs were given ownership of the transmission firm, but were later required to divest their shares in 1995 so that a new privately-owned transmission company could be created, the National Grid Company (NGC). NGC both owns and operates the grid. It is responsible for grid expansion and upgrading. NGC’s rates are regulated by the Office of Gas and Electricity Markets (OFGEM). All generators and wholesale customers have open access to the transmission grid.

The two generation companies, National Power and PowerGen, held the CEGB’s non-nuclear power facilities. In 1995, the government created a new firm, British Energy (later privatized), to manage the country’s modern nuclear power plants. Another state-owned firm held the country’s older nuclear reactors.

The wholesale spot market opened to competition in 1990. Forward contracting was permitted. The wholesale market was governed by a uniform market clearing price similar to that of California. Generators bid their power into the pool, and the highest price (the system marginal price) along with an additional capacity payment became the market-clearing price. Some argue that market power was being exercised because some generators charged prices six times higher than comparable generators. It has been argued that National Power and

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PowerGen were able to manipulate the market price above competitive levels.\footnote{182} By 1992, the system marginal price had risen by approximately 25 percent.\footnote{183} From 1990 to 2001 the average consumer’s bill for electricity decreased by 30 percent in real terms.\footnote{184}

Continuing concerns with the exercise of market power in the wholesale market eventually led to further market restructuring in 2001. In March 2001, the uniform price system was replaced with a bilateral, pay-as-bid system trading between generators, retail intermediaries, traders and customers (i.e., there is no uniform clearing price; individual transactions establish their own specific price), known as the New Electricity Trading Arrangements (NETA)\footnote{185} The Office of Gas and Electricity Markets (OFGEM) conducted a study of the first year of the NETA, finding that wholesale spot electricity prices fell by 40 percent from the announcement of the NETA in 1998 to the end of the first full year of the NETA in 2002.\footnote{186} Approximately half of this decrease in wholesale prices occurred during the first year of NETA. As a result, following the first two months of NETA, many small generators complained that NETA adversely affected their profitability and that such an outcome was not consistent with the government’s policy of encouraging the use of renewable and energy efficient generation methods.\footnote{187} In response to the concerns of smaller generators, OFGEM altered the market’s trading rules in 2003 by requiring the National Grid Company to pay directly smaller distributed generators “for the benefit of reducing demand on the transmission system.”\footnote{188}

\footnote{182} See Kwoka (1997).  
\footnote{183} Ibid., p. 51.  
\footnote{188} OFGEM, \textit{Rule changes to the electricity wholesale trading arrangements to benefit smaller generators}, (March 28, 2003).
However, the NETA results are controversial and inconclusive. Analysts have found it difficult to assess how much of the drop in price is due to the NETA preventing market power abuses and how much was caused by increased generation competition fostered by new entry and mandated divestiture.\textsuperscript{189} In order to mitigate market power concerns, during the 1990s PowerGen and National Power were required by the industry regulator to divest additional generation capacity to independent and other electricity generators.\textsuperscript{190} In England and Wales, in 1990/1991, the two non-nuclear generation companies had a combined 77 percent share of England and Wales generation market.\textsuperscript{191} The remaining share of the market belonged to nuclear power generation (14 percent) and independent and other electricity generators (9 percent).\textsuperscript{192} By 2001/2002 PowerGen and Innogy (formerly National Power) accounted for a combined 25 percent of the market with 14 percent belonging to British Energy and the remaining 61 percent held by independent and other electricity generators.\textsuperscript{193} There are now approximately 40 producers in the country.\textsuperscript{194} Thus, the government’s commitment to competitive generation markets through divestment by PowerGen and Innogy rather than NETA may explain the reduction in prices.

Under the old power pool arrangements England and Wales offered incentives for generators to maintain additional generation capacity. This was accomplished by including a “capacity payment” in electricity charges. Generators were compensated by a payment per kWh of declared but unused capacity. However, there were concerns that generators were abusing the capacity payment system. Generators are alleged to have announced in advance that certain

\textsuperscript{189} Joanne Evans and Richard Green, \textit{Why Did British Electricity Prices Fall After 1998?}, (Centre for Economic Policy, University of Hull Business School: January 2003).
\textsuperscript{190} Hunt (2002), p. 357.
\textsuperscript{191} OFGEM, \textit{The review of the first year of NETA: A review document, Volume 1}, (July 2002), p. 36.
\textsuperscript{192} Ibid.
\textsuperscript{193} Ibid., p. 40.
\textsuperscript{194} Ibid., p. 36.
generation units would be unavailable, decreasing the reserve and increasing the capacity payment. The generator would then bring the unit back online, allowing it to collect the increased capacity payment on the unit. With NETA capacity payments no longer occur. In 2002, generation capacity was estimated to be in excess of maximum demand by 22 percent. Whether adequate capacity will be maintained without a premium will require monitoring in future years; the use a capacity reserve requirement may have been a prudent alternative to capacity payments. In the short-run, the NETA does not appear to have had an adverse impact on new generation investment. Approximately 1500 MW of new generation was expected to be in-service by the end of 2002 with an additional 3700 MW of new generation anticipated to be in-service by the end of 2004.

The retail market was incrementally opened to competition and regulation. In 1990, users with a demand of 1 MW or more had the option of buying electricity on the competitive market. Real-time pricing for large industrial users was instituted beginning in 1991. In 1994, retail competition was made available to customers with a maximum demand of 100 kW or more. In 1998 the process of opening up the under 100KW market began. All customers were able to choose their supplier by May 1999. Initially, retail prices were subject to a RPI-X regulation. In April 2002, OFGEM eliminated retail price controls. By June 2003, the RECs had 61 percent of the market and new entrants had 39 percent of retail customers.

196 Ibid.
198 OFGEM (July 2002), p. 48
200 OFGEM.
4. PJM-Pennsylvania

The Pennsylvania, New Jersey and Maryland (PJM) market represents a relatively successful restructuring effort. In April 1999, the Pennsylvania wholesale electricity market was restructured. The market was initially composed of vertically integrated investor owned utilities companies with standard rate-of-return regulation. The reform initiative started in 1996 with Pennsylvania’s Electricity Generation Customer Choice and Competition Act. The act mandated the unbundling of electricity rates. However, incumbent utilities were not required to divest themselves of generation facilities to recover stranded costs. Electricity is traded through bilateral contracting and a uniform-price spot pool. All exchanges, even bilateral contracts, were required to take place in a central market or pool.\(^{201}\) PJM uses a locational marginal pricing (LMP) system (described above).\(^{202}\) LMP rates are determined in the PJM spot market. IOU retail prices were capped, with residential and commercial customers receiving an eight percent rate reduction.\(^{203}\)

With respect to stranded costs, Pennsylvania’s PUC authorized incumbent utilities to recover stranded costs through a non-bypassable CTC that is reviewed and adjusted for every customer that switches to an alternative supplier on an annual basis.\(^{204}\) The CTC is to be charged for a maximum of nine years or until stranded costs are recovered, whichever comes first.\(^{205}\) The PUC calculates the amount of stranded costs that each utility is allowed to recover and reviews and adjusts the CTC annually.\(^{206}\) Some utilities divested generation facilities in order to

\(^{204}\) Crow (2001).
\(^{205}\) Ibid.
\(^{206}\) Ibid.
accelerate stranded cost recovery.\textsuperscript{207} The retail rates of incumbent utilities are to be regulated until stranded costs have been recovered.

The privately-held IOUs own the PJM transmission grid, with fees regulated by FERC. As with California, open access to the grid is mandated by the \textit{Energy Policy Act} and FERC’s Order 888. Transmission capacity decisions are made by PJM Interconnect, the independent system operator, which designs a Regional Transmission Expansion Plan.\textsuperscript{208} The plan is prepared through consultations with relevant stakeholders (e.g., transmission owners and generators) through a Transmission Expansion Advisory Committee.\textsuperscript{209} PJM’s consultative transmission grid expansion approach will need to be assessed in the future to determine its efficacy.

In 1999, the six largest firms in the PJM generation market accounted for approximately 78 percent of total capacity (each firm had a capacity share of between ten and 17 percent).\textsuperscript{210} Recalling Borenstein’s observation about the market share that may allow for the exercise of market power, PJM would appear to have the potential for problems. Indeed, Mansur argues that in the summer of 1999, the price of electricity was 41 percent above the price that would have prevailed in a “perfectly competitive” market.\textsuperscript{211} He contends that generators used their small, high marginal cost plants to raise the system peak price above competitive levels.\textsuperscript{212} The evidence with respect to market power in 1999 is inconclusive. The PJM’s Market Monitoring Unit (MMU) found that “[in 1999] price increases were the result of a combination of factors including scarcity and market power [during peak demand periods] but that it is not possible to quantify the relative importance of these two factors.”\textsuperscript{213} Overall, in 1999, the MMU concluded

\begin{flushleft}
\textsuperscript{207} Kiesling (2001), p. 4.
\textsuperscript{209} Ibid.
\textsuperscript{210} Mansur (2001), p. 36.
\textsuperscript{211} Ibid., p. 29.
\textsuperscript{212} Ibid., p. 6.
\end{flushleft}
that “under most conditions, PJM energy and capacity markets have worked effectively and competively.”

There has been new entry in the PJM generation market since 1999. In 1999, there were a total of 15 companies owning marginal generation units; in 2002, there were 27 companies owning marginal generation units. The use of nodal pricing may have facilitated new generation entry. In 2002, the MMU concluded that, despite continuing concentration concerns, market power was not exercised and that “PJM market results were competitive in 2002.” Wholesale prices have remained stable through this period. In 1999, the hourly average system-wide LMP in the PJM was US$28.32/MWh differing little from 2000 (US$28.14/MWh), 2001 (US$32.38/MWh), and 2002 (US$28.30/MWh).

The PJM has a capacity reserve requirement. The PJM requires “all load-serving entities” (i.e., utilities and retailers) to have contracted sufficient capacity to satisfy peak demand and hold a 19 percent reserve (the reserve is reviewed and adjusted over time). The reserve margin provides protection against supply/demand shocks by encouraging the use of forward contracts (though not necessarily long-term contracts) to provide incentives for the construction of adequate generation capacity.

Retail access was implemented incrementally in Pennsylvania. As of January 1999, two thirds of consumers were able to choose their electricity supplier. All consumers had retail access by January 2000. In 2001, there were approximately 130 power suppliers in the state. If a consumer does not select a competitive retailer the incumbent utility becomes the default supplier, obligated to offer the capped rate. Similar to California, in Pennsylvania, the IOU rate

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214 Ibid.
216 Ibid., p. 4.
217 Ibid., p. 19.
caps remains in effect until a firm recovers its stranded costs. Only one utility, Duquesne Light, has recovered its stranded costs; however, it has agreed to abide by the rate cap through 2004. As result of the retail price cap, many customers that switched to a non-incumbent retailer would switch back to the incumbent during the summer in order to take advantage of the capped rate. In July 2000, the PUC increased the retail rate that incumbent utilities must charge in order to prevent consumers from gaming the system. In January 2001, the state randomly selected 300,000 consumers that had not switched to a competitive retailer and required them to contract with a new energy supplier. Consumers are free to opt out of the program without penalty.

5. Alberta

As with other jurisdictions the deregulatory initiative in Alberta was temporarily compromised by a reluctance to pass higher wholesale prices on to consumers and a lack of restructuring in the generation sector. Alberta began to reform its electricity market in 1995 through the *Electric Utilities Act*. Prior to reform the market was composed of three vertically integrated utilities with assigned service areas. These three firms accounted for 90 percent of the province’s total generation capacity. Two of the utilities were privately owned, the remaining utility was municipally owned by the City of Edmonton. The private utilities were regulated by Alberta’s Energy Utility Board (AEUB). Electricity was purchased by the government at a regulated, cost-of-service rate and then resold to utilities’ distribution divisions at an averaged, uniform price.

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220 Ibid.

221 Ibid.


The Electric Utilities Act mandated that the utilities transfer control of their transmission assets to an independent system operator. A mandatory uniform price spot market power pool was established in 1996. The Act mandated that from 1996 to 2000, the generation price would continue to be set at a cost-of-service rate for regulated generation (i.e., incumbent generation built before 1995). Transmission and distribution rates continued to be set by the AEUB. The province did not require incumbent utilities to divest generation capacity.

In 1999, to encourage competition in the wholesale market, the government mandated that the incumbent utilities divest the production rights of their generation assets, but did not require divestiture. The generation rights, called Power Purchase Arrangements (PPAs), would be auctioned to private investors. The PPA required the bidder to purchase a fixed output of an individual generating station for 20 years. The owners of the generation rights are required to bid all of their power into the Power Pool, but were permitted to enter into long-term hedging contracts with customers. A PPA contract required the buyer to pay the incumbent owner the marginal cost of generation of each unit of electricity produced and bid into the Power Pool, plus a fixed monthly payment determined by regulators. In exchange, the owners of PPA could bid the power produced by the plants covered by the PPA into the Power Pool, retaining the revenue.

The auction took place in 2000. Seven bidders participated with five winning PPAs, although not all available generation rights were sold. The low number of bidders has given rise to allegation of market power abuse. Because the number of bidding firms was low compared to number of contracts up for auction, and because firms faced a 20 percent total capacity limit,
firms may have had a tacit understanding not to bid up prices, allowing one firm to win individual auctions.\footnote{Wayne Silk, \textit{Alberta’s Road to Competitive Electricity Markets}, Canadian Bar Association Annual Fall Conference on Competition, (2001), p. 15.} An alternative explanation for the lack of bidders may be that the private sector was not convinced that Alberta’s provincial government was fully committed to privatization and were concerned about the risks of not owning or operating the generation facilities. These risks may have contributed to heavily discounted PPA bids. Given these problems it may be that divestiture was a more suitable course of action.

Wholesale prices in Alberta consistently increased between 1996 and 1999. Between 1999 and 2000 the Power Pool price rose dramatically from an average of $42.74/MWh in 1999 to $133.22/MWh in 2000.\footnote{Alberta Electric System Operator, \textit{FastFacts}, (May 2003). \texttt{http://ets.powerpool.ab.ca/corp_info/publications.html}} In response to the rising prices during the summer of 2000, the Alberta Market Surveillance Administrator (AMSA) conducted an investigation into power pool pricing behaviour.\footnote{Alberta Market Surveillance Administrator, \textit{Report on Power Pool of Alberta Prices – Summer 2000}, (October 2000).} The AMSA report argued that there may have been evidence that economic and physical withholding had occurred. Specifically, the investigation claimed that electricity was being sold at prices that exceeded the marginal cost of production.\footnote{Ibid., p. 17.} Second, the AMSA claimed that generators may have kept generation capacity off-line without a valid physical or operational justification.\footnote{Ibid.}

Additionally, it has been argued that prices increased because exports and imports were permitted to set the market-clearing price (British Columbia was importing electricity from Alberta to re-export to California).\footnote{Daniel et al. (2001), p. 22.} Rising natural gas prices also contributed to rising
wholesale prices because many marginal generation plants were gas fired.\textsuperscript{235} Also, the province had little import capacity as its transmission grid was interconnected with only British Columbia and Saskatchewan.\textsuperscript{236} It was also argued that the initial linkage of price to cost in 1995 suppressed the price of electricity in the province and discouraged investment in new generation.\textsuperscript{237} In November 2000, Alberta changed its wholesale pricing system to exclude imports and exports from setting pool prices.\textsuperscript{238}

Wholesale prices fell significantly following these changes and the resolution of the supply crisis across western North America (i.e., the California electricity crisis), and new generation entry. The average real-time wholesale spot price was $133.22/MWh in 2000, $71.29/MWh in 2001 and fell to $43.93/MWh in 2002.\textsuperscript{239} Approximately 2500 MW of new generation capacity was added to the Alberta system between 1998 and 2002.\textsuperscript{240}

Alberta had planned to introduce full retail competition and price deregulation by January 2001. However, when prices increased the government suspended these plans (except for large industrial customers) and capped retail rates.\textsuperscript{241} The government spent approximately $2 billion in rebates (retail customers received a $40/month rebate for 2001); the rebates were funded from the proceeds of the PPA sales.\textsuperscript{242} Residential and farm consumers will not have to face fully deregulated retail prices until July 1, 2006 (recently extended from an initial date of January 1, 2006). Small commercial and industrial costumers (users of less than 250,000 kWh/year) also will not have to face deregulated retail prices until July 1, 2006 (recently extended from an initial date of January 1, 2004). In the meantime, residential, farm, small commercial and industrial

\begin{thebibliography}{9}
\bibitem{235} Ibid., p. 22.
\bibitem{236} Alberta Advisory Council on Electricity, \textit{Report to the Alberta Minister of Energy}, (June 2002), Appendix C.
\bibitem{239} Power Pool of Alberta, (2003).
\bibitem{242} Ibid., p. 21.
\end{thebibliography}
customers have the option of choosing a retailer or the regulated rate tariff (formerly called the regulated rate option). In November 2000, the regulated rate was capped at 8 cents per kWh. In 2001, the rate was raised to 11 cents per kWh.

In 2002, the government ceased to set a province wide regulated rate. Energy suppliers are permitted to request approval from regulators (i.e., AUEB, municipal regulator or a Rural Electrification Association) to recover or refund the amount by which the regulated rate differs from their procurement costs through customer bills. When full retail price deregulation occurs the regulated rate will become a pass-through rate of the wholesale price provided by a default supplier for customers who do not sign a contract with an electricity retailer. The government’s willingness to allow the regulated rate to increase appears to have prudent policy. In anticipation of full retail price deregulation approximately 5200 MW of new generation capacity is expected to be added to the Alberta system between 2003 and 2006.\(^{243}\)

6. Australia-Victoria\(^{244}\)

Many of the states within Australia began deregulating their electricity markets during the 1990s. The state of Victoria pursued the most aggressive restructuring of electricity markets in the country. Prior to deregulation electricity was supplied in Australia by vertically integrated state-owned monopolies. In Victoria, electricity was generated, transmitted and distributed by the State Electricity Commission of Victoria (SECV). In 1993, the state government separated the SEVC into its generation, distribution and transmission components.

The generation component was split into five companies. Initially, the state government implemented cross-ownership restrictions between existing generators in Victoria and other generation firms, including new generation capacity; these restrictions have been modified on

\(^{244}\) See DOE (1997), pp. 39-60.
numerous occasions since restructuring. The state’s 29 distribution companies were merged into five companies. The state’s transmission grid was allocated to a new SOE, PowerNet Victoria. Beginning in 1995, Victoria began to privatize the newly created generation and distribution companies. The transmission grid was privatized in 1997. However, planning of the state’s transmission network is the responsibility of a new SOE, the Victorian Energy Networks Corporation. The government-owned Victoria Power Exchange (VPX) was created to operate and administer the spot market and operate the transmission grid.

Wholesale prices were deregulated. Victoria uses price-caps benchmarked by CPI-X to regulate distribution rates. The government also regulates retail prices by imposing ceilings on price increases (there is no evidence that it has ever allowed retail prices to fall below wholesale prices). In December 1998, a national competitive uniform-price wholesale market interconnecting Victoria, New South Wales, South Australia and Queensland was implemented. The VPX was phased-out and the spot market is now managed by the National Electricity Market Management Company (NEMMCO), which is owned by the states and territories participating in the National Energy Market (NEM). The pool sets the price for the entire NEM region unless there are transmission constraints. The NEM transmission grid is regulated by the Australian Competition and Consumer Commission (ACCC) through CPI-X rate-of-return regulation. There is mandatory open and non-discriminatory access for generators and retailers to the transmission and distribution networks. Consumers, retailers and generators may enter into bilateral forward contracts.

Wholesale spot prices decreased following the initial restructuring period but have experienced volatility, leading some to question the deregulated market’s ability to maintain adequate capacity reserves and raising allegations of market power abuses. The average annual
spot price in Victoria increased significantly from A$26.11/MWh for the fiscal year 1999-2000 to A$45.39/MWh for 2000-01. Prices then proceeded to fall to A$30.97/MWh in 2001-02 and A$27.54/MWh in 2002-03.

Studies commissioned by the ACCC concluded that in 2000 and 2001 electricity generators engaged in both economic and physical withholding of electricity capacity in Victoria and other Australian states “in order to create artificial price spikes.”\textsuperscript{245} The ACCC analysis concluded that a partial cause of market power abuse were impediments to forward contracting, including “barriers to long-distance trading in the NEM which facilitate the exercise of local market power.”\textsuperscript{246} Market power concerns also exist because generation markets, with the exception of Victoria, are concentrated in most Australia states (i.e., three or four dominant firms).\textsuperscript{247} A lack of demand-side responsiveness was also cited as contributing to higher prices and the ability to exercise market power.\textsuperscript{248} The ACCC’s analysis of the NEM indicates that forward contracting and import capacity should be viewed as tools promoting competition and preventing market power abuse; barriers to forward contracting should be removed to the greatest extent possible. However, forward contracting is already widespread. Some market observers estimate that 95-97 percent of electricity in the country is bought under contract.\textsuperscript{249} Others have argued that the rising prices provided the appropriate signal to the private sector that new generation investment was required, citing 856 MW of new committed peak generation projects undertaken in Victoria since July 2001.\textsuperscript{250}

\begin{footnotesize}
\begin{enumerate}
\item Australian Competition and Consumer Commission (ACCC), \textit{Changes to bidding and rebidding rules-Draft Determination}, (July 2002), p. 37.
\item Ibid., p. 51.
\item ABARE, \textit{Competition in the Australian national electricity market}, (January 2002).
\item ACCC (2002), pp. 51-2.
\end{enumerate}
\end{footnotesize}
Although still in the early stages, retail competition has not been embraced by consumers. Retail competition and retail price deregulation was introduced incrementally in Victoria. In December 1994, Victoria allowed retail competition for customers with peak demand in excess of 5 MW. In July 1995, consumers with demand in excess of 1 MW were able to choose their retailer. Retail competition was extended to customers with consumption greater than 750 MWh/year in 1996, and to those with at least 160 MWh/year in 1998. In January 2001, consumers with demand in excess of 40 MWh/year were able to choose their retailer; retail competition was extended to all remaining consumers in January 2002. Despite full retail competition, few customers have switched from incumbent suppliers (by April 2002 only 7500 small customers in Victoria had switched retailers).

Prior to full price deregulation retail prices were regulated through CPI-X regulation. From 1997-1999 the Victorian government mandated that residential electricity rates be reduced by at least one percent, in real terms, every year. Additionally, small business rates were required to be reduced by 20 percent, in real terms, over the first three years of deregulation. Between 1989 and 1999 average electricity charges, in real terms, fell by 20 percent. Between 1995 and 1999, some businesses experienced electricity savings of up to 55 percent. Formally, retail electricity prices in Victoria are no longer regulated; however, the government reserves that right to constrain retail price increases if it decides that they are not reasonable.

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251 See Essential Services Commission, Special Investigation: Review of the effectiveness of Full Retail Competition for Electricity, Final Report, (September 2002).
252 Moran (April 2002), pp. 33-34.
254 Ibid.
V. Conclusions

Electricity market restructuring is complex for a number of technical reasons. However, the reluctance of jurisdictions to pass on higher electricity prices to residential consumers makes the problem more complicated. It still remains to be seen if a jurisdiction can fully commit to full retail price deregulation in the long-run. This review makes it clear that passing on higher electricity prices to consumers represents the most significant obstacle to successful electricity market reform. In many cases efficiency may require prices to increase after deregulation. Failing to expose consumers to the “true” costs of generation and transmission eliminates demand responsiveness (e.g., shifting consumption patterns and using energy efficient products). A lack of demand responsiveness amplifies the need for excess generation and transmission capacity to maintain system reliability at peak times, increasing the probability of system failure in the presence of a shock (e.g., extreme temperature or unexpected generator outage), increasing the probability of restructuring “failing.” Cicchetti and Long argue that “[it] is unrealistic to think that it will not take time for the market to equilibrate once supply and demand balance. That will never happen unless regulators and politicians allow the market to send appropriate price signals.”257 Perhaps the blackout of August 2003 will change consumers’ attitude towards electricity pricing, such that they are more willing to pay the “true” cost of generation and transmission in order to maintain system reliability and supply security.

Jurisdictions are also struggling to find a balance between competition and regulation. First, allowing limited vertical integration between distribution and generation does not appear to have significantly harmed restructuring efforts in PJM and England and Wales. Indeed, the efficiencies of vertical integration may be one factor behind the success of these jurisdictions. Second, as the United Kingdom’s experience indicates, payments to generators to maintain

excess capacity, while subject to abuse, need not fully offset the price reductions resulting from competitive markets (it remains to be seen if England and Wales will continue to maintain adequate capacity reserves now that NETA has eliminated capacity payments). Alternatively, PJM’s requirement that all load-serving entities hold reserve capacity also appears to be consistent with relatively stable prices. While such policies create inefficiencies they may be necessary to signal to the private sector that the government is committed to deregulation. Third, claims of market power abuse and concentration problems have been made in jurisdictions that engaged in relatively aggressive ex ante generation restructuring; in other jurisdictions (e.g., California) observations of market power abuse can be argued to be a product of restructuring (e.g., requiring incumbent utilities to purchase electricity on the spot market). Fourth, regarding the monopoly sectors of the electricity market (i.e., transmission and distribution), there is a lack of evidence regarding the development of new transmission capacity following deregulation (e.g., while attractive in theory, whether nodal pricing, performance-based regulation, and commercial considerations provide stronger incentives for efficient transmission expansion over time compared to postage stamp pricing, traditional rate-of-return regulation and close state oversight). Fifth, some stranded cost recovery is likely appropriate to avoid political opposition and enhance the credibility of a jurisdiction’s restructuring initiatives. Sixth, evidence suggests that both industrial and residential electricity consumers reduce demand in response to increases in prices.

Emerging from recent reform initiatives is the conclusion that transition plans should focus on restructuring the generation market so that it is effectively competitive prior to full retail price deregulation.258 The reasoning is that if the market is effectively competitive fewer rules of conduct (e.g., generation price caps and ownership limits on generation capacity) will be

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necessary since market discipline will occur.\textsuperscript{259} This is not to say that restructuring is more important than market design, but it may indicate that the efficient sequencing of reform may be to assess the possibility of restructuring the market (e.g., vertical and horizontal divestiture, grid expansion, etc.) followed by designing market conduct rules based upon the degree of competition deemed possible from restructuring.

While there is some debate regarding sequencing issues and whether supply or demand should be the focus of reform there are some critical factors to observe from this review of electricity deregulation: (1) significant \textit{ex ante} generation market restructuring is required to mitigate market power problems and encourage future entry (this is especially important in jurisdictions moving from a vertically integrated state-owned monopoly to competitive markets); (2) because of the government commitment problem sufficient transmission and generation capacity to prevent price volatility caused by exogenous shocks (e.g., extreme temperatures) at the time of market opening is essential; (3) mandated non-discriminatory access to transmission and distribution facilities should deal effectively with access concerns (although such action may discourage self- and distributed generation investment); (4) market participants should face few impediments to short, intermediate and long-term bilateral contracting; (5) there is some evidence that greater reliance on forward markets is preferable to primary dependence on the spot market; (6) for reasons of political feasibility, it appears prudent to incrementally deregulate the retail market; and, (7) ultimately, with or without retail competition, demand responsiveness must be pursued for most consumers; at the very least, wholesale price pass-through should be permitted.

Overall, whether effective competition can occur within a period of time acceptable to government and consumers remains an open question. Indeed, as Borenstein and Bushnell have

\textsuperscript{259} Ibid.
noted, “short-run benefits are likely to be small or non-existent, and the long-run benefits, while compelling and supported in theory, may be very difficult to document in practice.”\textsuperscript{260} The status of restructuring in the United States shows that the commitment problem is quite severe. It is of note that of the jurisdictions reviewed in this paper the most successful restructuring and deregulation experiences are from the United Kingdom and Victoria. Both of these jurisdictions restructured their electricity markets from a state-owned vertically integrated monopoly to a deintegrated and privately owned market. This may suggest that the main benefits from restructuring arise from transferring ownership from the state to the private sector.

As Costello recently notes (just prior to the blackout of 2003), with respect to the United States, “in a democracy where people have varying views it has become obvious that a lack of political will in favor of a market oriented electricity industry does not exist at this time.”\textsuperscript{261} The high costs of failure make effective electricity deregulation a difficult undertaking. In light of the recent reform setbacks in Ontario and California, the continued “fine-tuning” in England and Wales, and the black-out of 2003, it remains highly questionable how many jurisdictions possess the political will to implement the aggressive steps necessary for successful market reform. The inability of politicians to refrain from intervening in the restructured market may, in certain circumstances, make existing regulated structures preferable to market reform.

\textsuperscript{260} Borenstein and Bushnell (2000), p. 2.
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