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Electricity Restructuring and Regulation in the Provinces: Ontario and Beyond

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Abstract

Competitive electricity markets are artificial markets with extensive rules for all participants arising from the complex interconnections of the electricity network. Governments or regulatory agencies oversee the market design process and the operation and maintenance of the market, so market design is necessarily a political process. The conceptual design of the market must recognise the political forces that will operate on the market design process so that the political process will not thwart the intended outcome of the market as it has in some jurisdictions including Ontario.

The limited ability of consumers to understand changes in the electricity sector in the short run poses a real constraint on what can be achieved politically. Letting the market set the price means that governments cannot ensure any particular future price level and both theory and experience tell us that prices may increase after restructuring (California, Ontario, Alberta). This makes it difficult to sell restructuring to consumers who will be interested in the price they pay and not much interested in abstractions like efficiency.

Another challenge for electricity restructuring is that the starting points differ from one jurisdiction to another and the starting points matter. The problems are different if you begin with a crown monopoly than if you have investor-owned utilities; if expected prices are higher than recent prices rather than lower; if governments have been deeply involved in the electricity sector rather than distant from it; if the public has experience with stable electricity prices rather than fluctuating prices.

Finally, the situation in neighbouring jurisdictions matters as well. Restructuring in a low-price jurisdiction surrounded by high prices will increase the prospect of price increases at home, while a high-price island is more likely to see its prices decline. If workable competition will be difficult to achieve at home, strong interties to neighbouring jurisdictions can improve competitive performance if the market is appropriately designed. Air pollution, like electricity, moves across borders, so one must assess and evaluate the pollution implications of competition and make any appropriate adjustments to the market design.

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1. Introduction

Restructuring of the electrical system and its operation involves at a minimum eliminating the traditional statutory monopoly on generation and allowing competition in generation as well as requiring the transmission owner to transmit power from generators to their customers. It may go further and establish a competitive wholesale power pool that sets an hourly (more or less) spot price. It may require integrated utilities to divest some of their assets and owners of the transmission and distribution networks, which remain natural monopolies, to be precluded from engaging in competitive activities such as generation and retailing. At the retail level, the distribution utility may retain a monopoly over the supply of electricity to customers in its service area, in which case it will purchase power on their behalf under contract and on the spot market, overseen by a regulator. Alternatively retail competition, also called retail access, may be mandated, allowing competitive retailers to arrange price terms with large customers, or with all customers, paying the distributor for delivering the power.[1]

The wave of electricity system restructuring during the last fifteen years has been stimulated by several forces. The development of the combined cycle gas turbine (CCGT) reduced the minimum efficient scale of a generating plant, allowing large electricity consumers to install their own generation and facilitating generation by non-utility generators. The development of new metering technology and the information technology infrastructure to communicate prices and consumption at low cost has facilitated competition in metering and in providing load-management services to consumers. While these technologies facilitate restructuring, however, Joskow (1997, p. 123) argued that the primary driver for restructuring in the US was the high prices charged by regulated utilities in the 1990's as they recovered the cost of investments in expensive facilities, when falling natural gas prices and increased efficiency of CCGT plants reduced the cost of new generation. Large customers rebelled at paying 6 or 7 cents per kilowatt-hour (kWh) to regulated utilities when the marginal cost of wholesale electricity was 2.5 cents/kWh and long run marginal cost was 3-4 cents/kWh. (Joskow, 1997, p. 126.) The solution was to introduce competition in generation, dealing with the high costs of incumbent utilities through an agreement on the amount of “stranded debt” that would be recouped, and who would pay for it. This seemed to be the logical next step after successfully eliminating rate regulation and introducing competition for railroads, trucking, airlines, natural gas, and long distance telephone rates from the late 1960's to the 1990's in the United States.

Economists like restructuring because it should improve efficiency. Competitive forces in the generation sector should squeeze the inefficiency out of monopoly generators, while market discipline should lead to better investment decisions. The wholesale price should reflect marginal cost, and passing this price to consumers should lead to optimal energy use and conservation, allowing the price to equate supply and demand in every hour of every day.

This paper will explore the institutional side of electricity restructuring. We start by reviewing the history of restructuring in Ontario and, more briefly, in Alberta. We examine electricity pricing to see what goals economists set for competitive markets and what impact the resulting pricing schemes have on participants in the electricity system. We then turn to politics,

[1] See Hunt (2002, Ch. 3) for a categorisation and description of restructuring possibilities.

evaluating the political forces that have operated on restructuring in Canada, particularly in Ontario, what effect they have had, and what implications those forces have for future electricity restructuring efforts. We will explore the importance of institutional starting points, such as crown corporations versus investor-owned utilities, on the restructuring process showing that initial conditions have a large impact on what is politically feasible. Finally, we look at the importance of neighbouring jurisdictions on the operation of an electricity market and on the competitive design that might be feasible. We will argue that you cannot have a successful restructuring without dedicated pursuit of the goal of economic efficiency, but that in addition you must pay strict attention to the politics, the starting point, and the neighbours, if your design is to succeed in practice.

2. History of Restructuring in Ontario and Alberta

2.1. Ontario

Almost a century ago, in 1906, the government of Ontario created the Hydro-Electric Commission of Ontario, which Sir Adam Beck developed into the provincial crown corporation responsible for generation, transmission and distribution of most of the electricity in the province. In the first half of the 20th century inexpensive power from the Adam Beck generation stations at Queenston Heights on the Niagara River provided low-cost electricity to the province. In the 1950's and 1960's HEPCO built coal-fired generating stations and in the 1970's and 1980's it added nuclear generation. The stations built in the second half of the century had much higher costs than Niagara Falls and raised average costs considerably. The Power Corporation Act required Ontario Hydro, as HEPCO was renamed in 1972, to provide "power at cost" which has become part of the culture and lore of electricity supply in Ontario. The utility did not pay taxes, nor was it intended to generate profits. The government of Ontario appointed the directors of Ontario Hydro, guaranteed all of its debt, and through the Minister of Energy could issue Policy Directives to Ontario Hydro. Ontario Hydro set its own rates, subject to review but not amendment by the Ontario Energy Board, and it set or approved rates for many of the municipal electric utilities that distribute electricity in areas not served by Ontario Hydro. With a headquarters very close to the Provincial Parliament buildings, Ontario Hydro was always close to the government, and there has been debate whether the government controlled Ontario Hydro or vice-versa.[2]

The completion of the Darlington nuclear station in the early 1990's, at a cost several times the original estimates, caused price increases exceeding 30% in three years as Ontario Hydro rolled the costs into its rates under the principle of power at cost. The resulting public outcry led the government to freeze the price in 1993 somewhat below actual costs, a freeze that lasted with little modification until 2002. In 1995, the Government of Ontario appointed an advisory committee chaired by Donald Macdonald to study and assess options for phasing in competition in Ontario's electricity system. The committee's report, *A Framework for Competition* was issued in 1996 and recommended the establishment of wholesale electricity

[2] For background information on Ontario Hydro, see Daniels and Trebilcock (1996) and the Advisory Committee on Competition in Ontario's Electricity System (1996).

competition. Retail competition was to follow in which distributors would manage a portfolio of supply contracts for customers who did not choose a retailer. The Macdonald Committee recommended that Ontario Hydro's generation assets be divided up among competing units: four separately operated nuclear entities with a single owner; that the fossil fuel plants be operated as independent units, and that the hydroelectric facilities be established as separate entities for each river system. (ACCOES, 1996, pp. 58-61.) The government issued a White Paper on electricity reform in November, 1997 which suggested that Ontario Hydro should be divided into a generation company (now Ontario Power Generation) and a transmission company (now Hydro One). (Ontario, 1997, p. 18.) There was no suggestion of breaking up or selling off the generation assets of Ontario Hydro. The White Paper proposed to achieve full wholesale and retail competition by the year 2000. (Ontario, 1997, p. 16.) The government then appointed the Market Design Committee which worked through 1998 to recommend an initial market design and a set of market rules. (OMDC, 1999.) The MDC was given to understand that it should not recommend breaking up and selling off the generation assets of Ontario Hydro, so it designed mechanisms to attempt to achieve a competitive result anyway, the Market Power Mitigation Agreement (MPMA). It was generally thought that the wholesale price when the electricity market opened would be about 3.8 cents/kWh, and independent power producers complained that much higher prices would be necessary to render new investment in generation profitable. The wholesale price had been around 4.3 cents. Ontario Hydro's average total cost was thought to be in the vicinity of 4.5 cents/kWh, so a "stranded debt" charge of 0.7 cents would be required on top of the market price.

Legislation followed that divided Ontario Hydro into a transmission company and a generation company, established the Independent Market Operator, and established the framework for a competitive wholesale and retail market.[3] Because OPG generated 90% or so of the electricity in Ontario, the MPMA provided a revenue cap for OPG at 3.8 cents/kWh which was to be relaxed as OPG sold or otherwise divested itself of control of generating capacity. The revenue cap would be lifted entirely when OPG controlled only 35% of the generating capacity. (OMDC, 1999, pp. 2-4 to 2-6.) The wholesale market incorporated an hourly spot market managed by the IMO, competition in generation, support for bilateral contracts, and default supply by local distribution companies (LDCs) to customers who do not choose a retail supplier. Wholesale prices were to be uniform across the province initially, but locational pricing was supposed to be examined 18 months after the market opened. (OMDC, 1999, p. 3-7 to 3-9). The Ontario Energy Board (OEB) was to regulate the monopoly elements of the system, including distribution and transmission, as well as regulating retailing and other activities. Restructuring considerably increased the workload on the OEB.

By 1998 eight nuclear units at Pickering A and Bruce A were out of service for serious maintenance and upgrading, although it was expected that most would be back on line before market opening.[4] The work proceeded slowly, however, and the by the time the market

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[3] *Electricity Act, 1998*, S.O. 1998, c. 15, Sch. A. The full title is: "An Act to create jobs and protect consumers by promoting low-cost energy though competition, to protect the environment, to provide for pensions and to make related amendments to certain Acts."

[4] Bruce A, Unit 2 was closed in 1993. In late 1997, three more units at Bruce A and all four units at Pickering A were laid up after a report identified management and operational problems.

participants were more or less ready for market opening, all eight nuclear units were still unavailable. OPG had, in 2001, leased the Bruce nuclear station to British Energy/Bruce Power, thus reducing its share of generation to about 70%. Unable to delay market opening any further, the government opened Ontario's competitive market on May 1, 2002, utilising a mandatory pool and passing the spot price to any consumer who had not signed up with a retailer for a fixed price. About one million consumers had signed contracts with retailers for electricity at prices around 5.7 cents/kWh. Consumers without retail contracts would receive a rebate if the revenue received by Ontario Power Generation averaged more than 3.8 cents per kWh over an entire year, with the rebate reflecting the proportion of total Ontario generation produced by OPG, expected to be about one-half in 2002.

Record drought and heat waves in the summer of 2002 combined with a failure to return nuclear units to service led to a peak price of $4.71/kWh on July 2, more than 100 times the normal price, and a monthly average price for July of 6.2 cents. (IMO, 2002a, p. 5.) September was worse, with a peak hourly price of $10.28/kWh and a monthly average price of 8.31 cents. (IMO, 2002b, p. 5.) The IMO issued repeated calls for conservation to avoid brownouts and blackouts. Consumers, who faced high bills as a result of higher prices and of running their air conditioners heavily during the summer, complained bitterly. On November 11, 2002, the government responded to those complaints and announced a price freeze for smaller consumers at 4.3 cents, leaving the wholesale market intact, and thus embracing the second worst feature of the California market design. The freeze would be retroactive to market opening, so that customers would receive rebates for the high summer prices.[5] The price freeze eliminated the price incentive to conserve electricity at times of shortage for small consumers. It damaged investor confidence, reducing the likelihood of investment in new generation facilities and of being able to sell or lease OPG facilities, thus paralysing the decontrol of OPG facilities.

In November, 2002, the average price since market opening had been somewhat over 5.5 cents/kWh, close to 50% above the price expected in 1998. Yet the MPMA ensured that consumers would receive a rebate for about half of the excess over 3.8 cents. Moreover the wholesale price represents less than half of the consumer's electricity bill. Table 1 shows the components of a typical Ontario consumer's monthly bill and the cost to the consumer per kWh at different wholesale prices. A wholesale price of 5.5 cents would increase the consumer's bill by 12%, and the net cost after rebate by only 6.2% over the baseline of 4.3 cents. An average wholesale price of 8 cents would increase the monthly bill by 37% and the net cost by 19%. The rebate was to be paid at the end of a year, however, and most consumers seemed either ignorant of the rebate or indifferent to it. Moreover, bills increased by more than this because consumers used large amounts of electricity for their air conditioning during the summer of 2002. One observer said that Toronto consumption was up 20% in the first six months of market operation. (Vegh, 2002.) Table 1 shows that a 20% increase in electricity consumption alone would increase the bill by at least 15%, an increase greater than that caused by the price increase over the first 6 months of market operation. Consumers seem not to have separated the increased price from the increased consumption.

February, 2003 was the worst month yet, with a peak price during a cold snap of

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By August, 2005, Pickering unit 4 was operating, and 2 and 3 were being abandoned.

[5] Press release, November, 2002, "Eves Takes Action to Lower Hydro Bills," Premier's office.

$3.75/kWh and a monthly average price of 8.86 cents. (IMO, 2003a, p. 5.) The weighted average wholesale price for the first full year of market operation to April 30, 2003, was 6.22 cents/kWh, 64% greater than the expected price of 3.8 cents and 38% above Ontario Hydro's average total cost of a few years previously of 4.5 cents. Small consumers paid 4.3 cents.

On a parallel track, the Premier of Ontario, Mike Harris, had announced in December, 2001 that the government intended to sell the transmission company, Hydro One. This was not required by the recommendations of the Macdonald Commission which had said explicitly that the transmission system could remain publicly owned or it could be operated under private ownership as a regulated monopoly. (ACCOES, 1996, p. 53.) The privatisation was challenged in a court which decided that the *Electricity Act* did not authorise the sale of shares of Hydro One. In quick succession the Premier announced that privatisation was off the table and then that the government would sell only a minority stake; the government passed legislation authorising the sale but did not sell. (Trebilcock and Hrab, 2005.) During the summer of 2002 a scandal erupted regarding compensation of the CEO of Hydro One, and in quick succession the government passed legislation allowing it to fire the directors of Hydro One, the directors resigned in protest, the government appointed new directors who fired the CEO who then sued for millions of dollars in damages for wrongful dismissal.[6] Needless to say, these gyrations heightened the unease among investors interested in the electricity business in Ontario.[7]

The price freeze was extended to somewhat larger consumers in 2003. It was, however, expensive for the government, since the wholesale price in 2003-04 averaged more than 5 cents. To mitigate future costs, on April 1, 2004, the price cap for small consumers was raised to 4.7 cents for the first 750 kWh consumed in a month and 5.5 cents for any additional consumption. Some of the nuclear stations were returned to service in 2003 and 2004. The summer of 2004 was cool and wet, so wholesale electricity prices were lower than in 2002-03. Still, the average wholesale price in 2004-05 was 5.31 cents (IESO, 2005). On April 1, 2005, the price cap was raised to 5 cents for the first 750 kWh and 5.8 cents for any excess; as well, starting in November, 2005, the threshold for the two prices would be 1000 kWh per month for November to April and 600 kWh per month from May through September. In addition, the price that OPG would receive for the output of its nuclear units and its baseload hydroelectric units was regulated by the OEB. In the future the regulated two-tier price for small consumers would be based on the regulated cost of power from prescribed OPG plants, the capped price of power from other OPG assets, the contract cost of power from independent producers, and the forecast spot market price. (OEB, 2005 a, b.)

2.2. Alberta

In Alberta, there were several integrated utilities including both investor-owned utilities and municipal utilities. Coal was the main fuel, followed by natural gas. The Alberta market design was established by the *Electric Utilities Act*,[8] in 1995, taking effect January 1, 1996. It adopted a mandatory power pool and passed the spot price directly to consumers, with

[6] Bernard Simon, "Ambitious Plans in Disarray at Canada Utility," New York Times, July 27, 2002, p. C3.

[7] For a detailed analysis of this period, see Trebilcock and Hrab (2005).

[8] R.S.A., 2001, c. E-5.5.

distribution costs and other fees added on. The wholesale price was determined by bids from generators, so the system operators could dispatch plants in merit order and loads could also bid load reductions. Like Ontario, Alberta rejected locational marginal cost pricing (allowing the price in various locations to differ based on transmission line congestion). Local distribution utilities retained the obligation to supply customers and the six largest distributors were assigned a share of the output of the existing generators at a fixed price. Consumers in Alberta who were worried about price fluctuations were encouraged to purchase hedges to mitigate those fluctuations. (Alberta Energy, 1997; McNamara, 1998.) Partial retail access, which allowed customers to purchase directly from retailers or generators rather than taking their LDC's price, began on April 1, 1999, after amendment of the *Electric Utilities Act* in April, 1998, with full retail access achieved in 2001. Further amendment to the *Electric Utilities Act* in 2003 created the Alberta Electric System Operator which took over the functions of the former Power Pool and the Transmission Administrator. The AESO operates the spot market and plans the electricity system. (AESO, 2004.)

Despite steady economic growth, there was little growth in generation capacity from 1994 to 1998 pending the resolution of some market design issues. Wholesale prices were stable during most of 1996, but rose sharply during the last quarter of 1996, although the average for the year was still only $14.42/MWh. In 1997 prices averaged $20.39, an increase of about 40% over 1996. The price averaged $42.74 in 1999 and rocketed $133.22 in the year 2000. (AESO, 2005, p. 2.) Consumers complained and the government implemented a consumer protection plan, the Regulated Rate Option (RRO). Residential consumers in 2001 paid a high regulated price, 11 cents/kWh, but received a rebate of $40 per month, yielding an average electricity cost of 6.5 cents/kWh for an average consumer. The RRO set a high marginal price for electricity, preserving the incentive to conserve electricity, but the fixed monthly rebate relieved the financial burden of the high price. For medium and large commercial and industrial customers the price was the same as in the RRO but there was a per-kWh rebate that reduces the net price to 7.6 cents/kWh. Starting in 2002, utilities offered their own RRO rates, which in November 2002 ranged from 4.8 cents to 6.8 cents/kWh, while retailers offered fixed price contracts.[9] This RRO has apparently brought stability to the Alberta market while encouraging conservation. However the generation market is highly concentrated, with two firms often setting the price, so a truly competitive result seems improbable.

3. Electricity Pricing: Incentives and Transfers

Electricity cannot be stored; it must be generated exactly when it is consumed. It can be transported long distances, but long distance transmission capacity is costly. These facts cause electricity markets to differ substantially from markets for many commodities. Understanding the behaviour of electricity markets requires some understanding of the shape of electricity demand and supply functions including the time variations of demand, of average and marginal cost pricing, of investment in generation capacity, and of retail competition. We will consider these issues in a hypothetical electrical service area, such as a large metropolitan area.

[9] See, http://www.customerchoice.gov.ab.ca/elect/images/summary_2002.pdf .

3.1. Supply, Demand and Price Volatility

A typical service area will have three types of generation facilities: baseload, mid-merit (medium cost), and peaking. Baseload plants have high capital cost and low operating cost; they can be nuclear, run-of-the-river hydroelectric, or coal-fired thermal plants. Mid-merit plants have moderate capital and operating costs; they are usually coal or oil-fired steam turbine plants, or combined cycle gas turbines (CCGT). Peaking plants have low capital cost and high operating cost, and often rely on a simple cycle gas turbine or storage hydroelectric power. Most electric utilities dispatch plants in merit order, meaning that the plant with the lowest marginal costs are operated first, then the higher-cost mid-merit plants, and finally the high-operating-cost peaking plants. Merit-order dispatch minimises the cost of generation.

The aggregate marginal cost curve for a typical fleet of plants rises slowly over a range of output as baseload and mid-merit plants are used, but rises rapidly as capacity is approached and peaking plants must be run. If some of the capacity becomes unavailable, the marginal cost curve will shift left. The mid-merit plants set the system marginal cost much of the time; in a competitive market, they usually set the price. The system marginal cost for PG&E in California was about $42/Mwh in a summer night, and over $60 during the day. (Kahn, 1988, p. 121.) Borenstein, Bushnell and Wolak (2002, p. 1385) find that the system marginal cost for California fossil-fuel plants in 1999 was about $35/mWh below 3,000 MW of load, rising gradually to $40 at 12,000 MW, and then rising more rapidly to more than $60 at 17,000 MW. Bunn, Day and Vlahos (2000, p. 109) reproduce a marginal cost function for the generators bidding into the National Grid Company in the UK with zero marginal cost up to 11,000 MW because the nuclear plants cannot be shut down in the short run. Marginal cost rises irregularly from zero at 11,000 MW up to 3.5 pence/kWh at 58,000 MW, then becomes very steep, rising to 10 pence at 60,000MW. The shape of aggregate marginal cost will vary from one jurisdiction to another depending on the mix of generating plants.

Turning from supply to demand, empirical studies have found price elasticities of demand for electricity to be relatively small in the short run and near unity in the long run. That is, consumers reduce their consumption only by a small amount in the short run, but they reduce consumption in proportion to the price increase in the long run. Baughman, Joskow and Kamat (1979, pp. 52, 70) estimated own-price demand elasticities for the residential and commercial sectors at -0.19 in the short run (one year) and -1.0 in the long run (20 years), while the corresponding elasticities in the industrial sector were -0.11 and -1.28. Ham, Mountain and Chan (1997, 132-137) studied the response of small commercial customers (less than 50 kW peak demand) to very short run price changes, looking at peak/off-peak time-of-use (TOU) pricing in Ontario and found own-price elasticities of -0.13 in the winter and -0.11 in the summer. Farouqui and George (2002, p. 48) report that TOU pricing results in an elasticity of substitution for residential consumers between peak and off-peak of about -0.17 and an on-peak own-price elasticity of -0.3, while larger commercial and industrial consumers exhibit elasticities in the vicinity of -0.9. Recent studies of dynamic pricing, in which the price is determined by real-time conditions, have yielded higher elasticities than the TOU pricing studied earlier, with elasticities greater than -0.5 and with on-peak elasticities greater than off-peak elasticities. (Farouqui and George, 2002, p. 49-50.) These elasticities should increase with the development of improved load management technology, the expansion of load management services by energy service companies, increased variability of prices, and improved customer information

regarding hourly prices and how to respond to them.

Restructured markets that are fully competitive use bids by generators to set a wholesale spot price reflecting the price-setting bid for that hour.[10] If generators cannot exercise market power, this spot price should represent the short run marginal cost of generation. Economists' enthusiasm for competitive markets arises from the use of this price to equate supply and demand in real time; at every moment (or hour anyway) generators and consumers are matching supply and demand at a market price. At the margin, the cost of generation should equal the value of consumption.

3.2. Price Volatility and Bill Variability

Shifts in either supply or demand may substantially increase or decrease the short run marginal cost, and thus the efficient price, especially if the system is close to full capacity utilization. In a competitive market, the spot price will respond at once to these factors. We should expect, and we do find, that price can vary considerably over a single day when demand approaches system capacity. Wolak (2000, p. 129, 130) studied price data from five restructured markets and found that the standard deviation of hourly prices within a year was actually greater than the annual mean price in a few instances, and was at least 1/3 of the mean in half of the cases. Hourly prices were much more volatile in fossil-fuel dominated markets than in markets supplied primarily by hydroelectric power. However when we look at variations among annual averages, the hydroelectric systems tend to be more volatile. The ratio of the highest to the lowest annual means in a jurisdiction ranged from 1.68 in England and Wales, to 1.99 in Victoria, Australia and 4.36 in Nordpool. This variation in annual means is very significant. Price variability is sometimes discussed in terms of price "spikes" which suggests that high prices are transitory events that would have little effect on the average monthly price. However if a system experiences a supply-demand crunch, as happened in California in 2000, in Alberta in 2000 and in Ontario in 2002 and 2005, the weekly and monthly average prices may be seriously affected. In California, the price rose from an annual average of about $30/mWh in 1998 and 1999 to an annual average of $115 in 2000. (Joskow, 2001, Table 1.) The average Alberta price in the year 2000 was 13.9 cents/kWh, more than five times the annual average in 1996, the first year of market operation. The average price in Ontario during the first full year of market operation was $62, 38% greater than the average total cost that had existed for several previous years. The annual average for 2003-04 fell to $51, and in 2004-05 it rose slightly to $53. Figure 1 shows monthly average prices in Ontario for 2002 through 2005. Ominously, the prices during June, July and August of 2005 are higher than in the same months in any of the preceding three years.

Unless a utility has considerable excess capacity, reliable plants that are very unlikely to suffer extended unplanned shutdowns, and a slowly growing economy or the ability to add capacity rapidly, one must assume that there is a significant chance that over a decade a supply-demand crunch may appear for a week or a month. This will increase prices. If significant capacity is lost (shutting down a nuclear plant) and has to be replaced with new investment, the crunch could last for several years. Any restructuring of the electricity market should be designed to handle these possibilities. There is the opposite problem that all generation may

[10] See Hunt (2002, ch. 7) for a description of several wholesale market arrangements.

work well and the economy could go into recession or a major user could close, leaving the system with unexpected excess generating capacity. This will lead to low spot prices, perhaps dominated by baseload marginal costs rather than mid-merit marginal costs. While a delight for consumers, this could be a disaster for generators relying on revenue from the spot price. Again, the market design should enable all parties to survive.

Charging customers the spot price is quite unlike the traditional practice of charging a regulated price fixed for a period of a year or more to all customers in a class: a fixed price/kWh at all times for small customers, a fixed price/kWh plus a demand charge for highest usage in the billing period for medium users, and perhaps more sophisticated peak-load pricing for largest customers. Indeed, MacAvoy argues that one of the main motivations of price regulation of public utilities in the US was to prevent rapid increases in prices, to stabilize prices. "The implication of stability was that the companies licensed for service would offer prices that on average over a decade would be no more than sufficient to cover the average total (variable and capital) costs of service for all classes of consumers." (MacAvoy, 1992, p. 12.) Ontario Hydro's mandate to produce "power at cost" also assumed the stabilization function - it was not required to break even every year.

Charging customers a marginal cost price or the spot price may be efficient but it can lead to variable electricity bills as was dramatically demonstrated in Alberta in the year 2000 when persistent high spot prices doubled or tripled normal electricity bills, and in Ontario in 2002 and 2003. If the utilities had still been under rate of return regulation, their cost-based prices would have barely risen in these years. Whether the utility operates at high marginal cost for 5% of the year or 10% of the year will only modestly affect its total costs. However if the price for all electricity generated in an hour is set by the marginal cost of generation in that hour, increasing the amount of time spent at high marginal cost by 5% can substantially increase the generator's revenue and, of course, the customer's cost. With marginal cost pricing, small shifts in supply or demand can affect the load-weighted marginal cost by much more than they affect average total cost.

There are several general solutions to the volatility of electricity costs in competitive markets. One is to abandon retail competition and for distributors to purchase a portfolio of long-run contracts for the supply of their customers. This insulates the distributor and its customers from the fluctuations in the spot price, abandoning the goal of efficient pricing. A second solution is for retailers or distributors to purchase a portfolio of electricity supply contracts covering most of their customer demand and to charge consumers a price that blends the cost of this portfolio and of the spot price for the remaining quantity. Unfortunately the marginal price paid by the customer responds only modestly to the spot price, losing much of the short-run efficiency of marginal cost pricing.[11]

The other solution is for retailers or distributors to enter into contracts for fixed quantities of electricity at fixed prices and to offer to consumers a price that is fixed for a specified quantity, with deviations from that quantity bought or sold at the spot price. Under this pricing arrangement, consumers face the spot price at the margin, but they buy and sell relatively little at that price so cost impact is modest. This combines the efficiency of the spot price with cost and revenue stability similar to that of rate-of-return regulation. Interestingly, in the fall of

[11] Many variations are possible. See, e.g., Borenstein (2001).

2000, the California PUC guaranteed that residential customers of San Diego Gas & Electric would pay no more than $75 per month for electricity in 2001 for the first 500 kWh per month; above that usage they would pay market rates. (Levesque, 2000, p. 14-15.)

3.3. Generation Investment

Regulated utilities, with their monopoly on generation, have traditionally forecast future demand and planned investment in new capacity to meet it. Plants are financed in anticipation of regulatory approval for the rates to pay for them. Indeed, one criticism of regulated utilities has been over-investment in facilities to minimize risks of power shortages and consumer complaints. Investment planning is made more difficult by the long lead times to plan and construct generation facilities: as much as a decade to construct a nuclear plant and as long again for environmental and planning approvals; up to five years for coal plant construction and another five for approvals; perhaps two years for construction of standard combined cycle gas turbine plants.

If the wholesale market is competitive, then private investors should be prepared to invest in new generation when the forecast wholesale price will bring a satisfactory rate of return on that investment. However there is debate as to the willingness of investors in competitive generation plants to face these uncertainties and long lead times unless they can sell most of the power under long-term contracts. In any event, such investments would likely attract risk premiums that would increase with the lead time involved and increase with the fraction of the load that could not be sold at a fixed price for a decade or two. While it has been argued that competition will lower the cost of new investment by forcing investors rather than customers to bear the costs of bad investments, this argument ignores the increased risk premium those investors will demand for bearing the risk. Thus capital costs for competitive generators must be substantially greater than for a regulated utility making the same investment. The experience in Australia, New Zealand, and the UK shows that private investors will build new capacity under some market rules. Indeed, it has been argued that high prices have stimulated new construction in most markets, even California. (Seiple, 2000; Rose, 2000.)

Investors need to know the rules so they can evaluate the investment. Uncertainty delays investment. Yet restructuring takes time, during which the rules are, necessarily, unclear. Investment may stop when restructuring is proposed seriously and not resume until after market rules are finally agreed, as in Alberta. If this takes five years and the economy is growing, a supply/demand crunch could emerge by market opening. The smoothest openings of competitive markets have coincided with excess supply, while the worst were those that opened with shortages, as in Alberta and California an Ontario.

If the new capacity is not small relative to the market, the price must rise above the target price, since the new capacity will depress the price once it comes on line. Over time, competitive prices in a market in which capacity investment is not small relative to installed capacity may follow a sawtooth pattern, rising until a new plant comes on line, then falling, only to rise again as demand grows.

4. Restructuring and Politics

The politics of restructuring includes two quite different questions. The first relates to the governance of the independent system operator and other institutions that will manage the market, dispatch the power, and maintain the rules. There is some literature on "governance," looking at institutional design, such as how the to structure the system operator in a competitive market or what interests should be represented on the board of directors of one or more corporations created during restructuring. Barker, Tenenbaum and Woolf (1997, pp. 47-48) mention it briefly.

The second question is how a government and/or regulator approaches the restructuring process and what forces does it respond to? Here the literature is relatively thin. Most of the literature on electricity restructuring is descriptive of what has happened in a jurisdiction, or prescriptive, with recommendations as to desirable elements of a restructured market. At the theoretical level, there are at least two broad theories as to how governments would behave in addressing regulatory issues generally and electricity restructuring in particular. One is the "public interest theory" in which government agencies are assumed to try to determine what will maximise public welfare and then to pursue policies to achieve this end. This is an attractive theory except that it seems not to explain much of what governments actually do. Joskow rejects "public interest" as a major force behind electricity restructuring in the US, accepting instead special interest pleading, specifically the desire of large customers to pay a price less than the average cost of generation in jurisdictions where that average cost is high. (Joskow, 1997, pp. 125-27.) Other models assume that policies emerge as the result of the self-interested activities of affected individuals and groups. One such model is the median-voter model, which predicts that voters and their elected representatives will generate policies that reflect the interests of the median voter in the relevant group(s). Stigler (1971) and Pelzman (1976) assume that regulation emerges in response to demands by industry for protection, and that regulators are captured by the regulated firms; this theory would predict that electricity restructuring would serve the interests of the most powerful stakeholders in the industry. Becker (1983) extended the self-interested explanation to explore the properties of systems in which self-interested groups compete for political outcomes, and Aidt (1998) applied a model of self-interest to the choice of environmental policy. Another set of models looks at the political process, incorporating the preferences of politicians and of agencies, so that policies are affected by the demands of supporters but also by the relationships of individuals within the government. (Keohane, Revesz, Stavins, 1998, pp. 554-58.) I have not seen applications of these theories of political decisions-making to the electricity restructuring process itself. I am persuaded that private interest theories that recognise the ideology of major political and bureaucratic players will have the most explanatory power, and therefore expect that the outcome of a restructuring process will be shaped to a large extent by the political influence of the major stakeholders and of small consumers/individual voters.

Ando and Palmer (1998) conduct an empirical analysis of the factors that induce legislators and regulators to adopt retail competition. Factors that increase the likelihood of a state moving toward retail competition include: one interest group that dominates the others; high regulated prices; lower prices in adjoining states; and larger price variations among utilities

within the state. The last three factors are all indicators that competition might lower prices for consumers as low-price generators outbid high-price generators. Hirsch (1999) is an historian who traces the political power of utilities over a century and finds that there was a consensus from early in the 20th century that electric utilities were a natural monopoly, but that in the US PURPA infringed on the power of the utilities starting in 1978, and that subsequently with increasing utility problems with the operations of nuclear plants and with meeting growing demand in the face of strict environmental requirements there was an increasing belief that competition could perform better. White (1996) calculates the expected gains and losses to consumers and utilities in each state and finds that restructuring has proceeded most rapidly where the expected price changes are the greatest.

Ontario's move to restructure seems to have been motivated by a broad consensus that Ontario Hydro was performing poorly by the 1990's, evidenced by the huge cost overruns at Darlington and consequent price increases. ACCOES (1997, p. 20-24) identified as motivators an increasingly competitive climate for Ontario industry; the steadily increasing price of electricity which was approaching that of US states; the expectation that electricity competition would lower prices in the US; the development of efficient small-scale CCGT generators, and the demand for a wider variety of services including metering and energy-management technology. It appears that major power users were strong supporters of competition. I have seen no evidence that small consumers wanted competition or customer choice, but the government's White Paper emphasised choice and the lowest possible prices for consumers as well as increasing jobs, presumably because of the competitive advantage that cheaper electricity would bring to Ontario industry. By the time that the MDC was in operation there were furious debates between those who thought the competitive price would be as low as 3.8 cents and those who said that no new power projects could be brought on line unless prices exceeded 5.5 cents.

While the government was attracted by the benefits of competition, it could not bring itself to support the necessary structural changes, mainly separating the control of individual Ontario Hydro generating stations and selling or leasing some of them so they would compete with each other. It compromised by embracing the benefits but not the costs. Here it tried to please two constituencies - consumers (small and large) who wanted lower prices and those who wanted to build new generation. In practice, the initial high prices displeased consumers and the price freeze on November 11, 2002 displeased generators and would-be investors.

The MDC's recommendation to pass the spot price directly to all consumers was radical, and was agreed upon by the Committee only after vigorous discussion. Its advocates liked the efficiency of the price signal that it generated, in addition to which it greatly simplified the administration of retail competition; if a customer signed up with a retailer the retailer would pay the spot price bill and send a bill to the customer based on their agreed price. The MDC felt that the risk of price volatility was addressed by the MPMA rebate, and the government was initially persuaded. In practice, consumers were either insufficiently informed about the rebate or did not care. After six months of market operation, the government could not withstand the public outcry and imposed the price cap, thereby satisfying small consumers but destroying investor confidence in the Ontario market for the foreseeable future. The imposition of the price cap was a political reaction to vigorous demands by an unorganized but numerous interest group: small consumers. Whether the government understood that this cap would undo all the work of the preceding six years is not clear. If so, it suggests the very short time horizon of the government

and its interest in being re-elected, rather than in preserving the new electricity market structure that had been erected at great cost.

The California electricity crisis was well-publicised in Ontario before our summer of high prices yet the Ontario government imposed a retail price cap on top of a market wholesale price: similar to the disastrous California price cap that had been roundly condemned by most observers. At an electricity conference in October, 2002 I was asked if we would repeat the California crisis. I explained the flaws in the California market and said in jest that we would not repeat the California crisis; we would have our own made-in-Ontario crisis. On November 11 the government gave us exactly that.

The Ontario experience offers a few lessons regarding the politics of restructuring. It does support the interest group model of political action. Generators and large consumers supported the restructuring process and helped push it forward. When small consumers concluded that they were being screwed by the new market the government stepped in to their rescue.

Ontario's experience also suggests the difficulty of developing policy in a field in which the underlying assumptions are changing. In the mid-1990's it appeared that competition would lower prices, which caused large consumers to support competition. By late 2002 it was clear that competition could increase prices dramatically, eroding support from large and small consumers alike. While the MDC felt that consumers were protected from priced increases by the MPMA, this protection was not sufficient for the high prices that were experienced.

How could governments in California and Ontario have ignored principles that in retrospect seem self-evident? Some answers are ominous for all jurisdictions. The intricate interconnections in an electricity system provide enormous opportunities for market participants to impose externalities on each other. (Wilson, 2002.) Extensive, detailed rules are necessary to minimize these opportunities and to ensure an economically efficient market design.[12] Yet every jurisdiction is different, so the market must be custom designed each time. The market is so complex that the market participants must be involved in the design to ensure that it meets local needs, to ensure that they understand it enough to participate intelligently when it opens, and to win their support. Observers have argued that in California some market participants injected design features that served their private advantage while contributing to the flawed performance of the market as a whole.[13] Subsequent government intervention made the problems worse, not

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[12] The Ontario market rules fill more than 20 mb of pdf files. See http://www.ieso.ca/imoweb/manuals/marketingdocs.asp (Aug. 9, 2005).

[13] "Getting it done fast and in a way that pandered to the many interests involved became more important than getting it right. The end result was the most complicated set of wholesale electricity market institutions ever created on earth and with which there was no real-world experience." (Joskow , 2001, p. 370.) "I said that the split between the ISO and the PX was primarily a device to create business and profit opportunities for middlemen such as Enron, and that the resulting inefficiencies and gaming would ultimately impose large costs on the market and on consumers." (Ruff, 2002.) "California built its market design on a flawed premise. . . . [T]he design of the California market embraced the notion that what little the system operator would do should be done inefficiently in order to leave even more coordination problems for the market to solve. This was an unprecedented experiment in markets that did not work in theory.

better. In Ontario, the MDC pursued a design that a majority felt would perform efficiently, only to have the entire market undermined by subsequent government intervention when prices rose. The OMDC worked hard to keep efficiency and the public interest as the guiding principles of its deliberations, and the government implemented many of its recommendations but could not hold the line once the market opened. Once the rules are written, how does the government resist the pleading of special interests when elected officials are unlikely to understand the technical details of the market and may not trust the political instincts of their staff, only a few of whom are likely to understand it well enough to give advice that is in the public interest? What set of objectives does the government bring to the table and what set of interests will it respond to? These are questions that must still be addressed if we are to pursue electricity restructuring successfully.

In Ontario's case, the market design relied initially on a rebate from OPG to protect consumers from high prices, although the rebate would be paid at the end of the year, but as OPG decontrolled its plants consumers would have to protect themselves from price fluctuations by purchasing power from retailers. There was little experience elsewhere to suggest that most consumers would do so. At market opening the consumer education program was inadequate to inform consumers of what was to come. In particular, the Ontario government had not prepared consumers for fluctuating prices. In the White Paper, the government wrung its hands about Ontario's high prices and said that prices and costs would be driven to the "lowest possible level," only technically avoiding an explicit promise of lower prices. (Ontario, 1997, p. 11.) The full title of the 1998 *Electricity Act* included the phrase "promoting low-cost energy through competition." In March, 2002, Minister Jim Wilson said that the Ontario Hydro monopoly was responsible for high prices, that consumers would enjoy a safe and reliable supply of electricity at the lowest possible cost, and that Ontario would have a reliable supply of electricity for the next decade.[14] Nowhere did the government's publicity say that prices might increase significantly.

This reveals a second general political problem: the selling of competition. The public will not easily understand the merits of fluctuating prices, nor of high prices at times of power shortage, nor even of prices high enough to cover costs. Governments can sell the public on a market if it means lower prices. If it means fluctuating prices or perhaps generally higher prices, the public will resist unless there some immediate crisis that could be solved with higher prices. Yet in jurisdictions in which the legacy generation has lower costs than new power sources, and this would include most of Canada if we reject new coal plants, competition and marginal cost pricing will more likely lead to high prices than low prices. The difficulty of explaining the merits of efficient pricing when it means higher prices is obvious. So, governments are likely to sell competition on the basis of lower prices, which in many plausible circumstances cannot be delivered without subsidy. When prices rise, the public rightly feels cheated and demands protection.

The implications of these political problems are stark. Governments have difficulty

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We now know that it did not work in practice either." (Chandley, Harvey, Hogan, 2000, pp. 2-3.)

[14] "Strengthening Ontario's Electricity Sector", interview with Jim Wilson, Globe and Mail, March 11, 2002, special supplement, p. M3.

resisting public demands for protection when prices rise as evidenced by the reaction in those three jurisdictions. Yet private investment will occur only if investors can reap the high prices as well as the low prices. The business press denounced Ontario's November 11, 2002 price caps as having crushed any hope of new private investment in generation. Indeed, Ontario has been forced to develop other methods of attracting new investment (again copying bad ideas from California).[15] The largest risk in competitive electricity markets may not be power shortages or heat waves but government intervention - sovereign risk. It is not clear what a government could do to prevent its own future intervention, nor to reassure investors once it has intervened.

These are problems for which the solutions are not obvious. If we became disillusioned about economic regulation because real regulators were captured by industry or other powerful interests, why do we think that a democratic restructuring process will not succumb as well? If competition means prices set by supply and demand, then prices may go up or down and no promise should be made about price levels after competition. How can a government that believes in competition pursue a market design process that is robust to the political pressures that may arise during the design phase and after market opening? I believe that it is too early to tell how often this process will create competitive markets that achieve the efficiency gains for which they are admired.

One can call for market designs that are politically robust as well as being robust to technical failures in various parts of the electrical system. But given the complexity of the problem and the lack of agreement on ideal market designs, how would we identify politically robust designs and how would we promote them? I find much to like in pricing systems for small consumers that yield real-time marginal prices with modest bill variations, such as the Alberta RRO or the San Diego fixed price for a base amount and market price for deviations from that amount, but unless a consensus develops around these features, or some others, it is not clear what would lead a jurisdiction to choose them. The design of politically robust markets is a work in progress.

5. The Importance of Starting Points

Each jurisdiction will have its own historic features that will influence the development of a market and the optimal design as well as the feasible design. These starting points are important because people tend to regard their current situation as a right and while they will accept improvements easily, they may resist taking away what they currently have; the disutility of a loss exceeds the utility of a gain of the same magnitude. This is an application of "prospect theory" articulated by Kahneman and Tversky (1979).

The first starting point is the ownership of the electric utilities by public bodies or by private investors. Ontario had a century-long tradition of ownership by the Province of most of the generation and transmission system and municipal ownership of most distribution not owned by the Province. This situation is repeated in much of Canada: provincial and municipal ownership dominate the electricity sector except in Alberta, PEI, Nova Scotia and Newfoundland. (Canada, 1999.) During that century the public perception of Ontario Hydro as

[15] For discussions of the California debacle, see: Berg et al. (2001), Borenstein (2002), Borenstein, Bushnell and Wolak (2002), Joskow (2001), and Sweeney (2002).

a public servant - powerful, expert and benevolent - was developed or carefully cultivated. If restructuring requires selling or leasing significant assets that have been publicly owned, the public must be persuaded that this is in their interest, which would likely require a major change in the public perception of the utility. This was not remotely accomplished in Ontario. Despite the well-publicised problems that Hydro experienced in the 1980's and 1990's, people continued to ask why the government was changing things. The inability to break up OPG or sell off its generating stations, because of public resistance, is a huge barrier to achieving a competitive market structure.

In Quebec, Hydro-Quebec may have even greater cultural and symbolic importance. The creation and growth of Hydro-Quebec is closely associated with the economic and political growth of the Province of Quebec. It is hard to imagine a situation in which any of the major hydroelectric generating stations of Hydro-Quebec could be privatised and sold off to create a competitive market structure.

Perhaps instead of selling assets of a crown corporation to private investors the utility could be divided into separate operating units still owned by the government but with instructions each to behave competitively. Before following this path one would want reassurance from successful experience with this model in some area of crown corporation activity.

On the other hand, in a jurisdiction with investor-owned utilities there is often little public affection for the monopoly utility. In such a situation there is little problem with public opinion and one must only confront the legal and financial issues involved in forcing a firm to divest itself of some of its assets.

A second starting point is whether the public utilities are fully integrated or vertically segregated into generation, transmission, and distribution utilities. Fully integrated utilities must be broken up to some extent, at least by separating generation from the other functions. Ontario's situation was mixed, with Ontario Hydro serving a number of large industrial consumers directly, and providing distribution service to many, particularly rural, areas of the province. In addition, Ontario had over 300 municipal electric utilities prior to restructuring, the smallest with only 113 customers. (ACCOES, 1996, p. 13.) Many of these were much too small to afford the conversion of their customer software to that appropriate for a competitive market and others were too small to acquire the expertise needed to operate in the new environment. Consolidation was needed but met with considerable resistance from the MEUs and their customers, who disliked handing control of their local utility to strangers. Jurisdictions with vertically integrated utilities will not have to deal with consolidation of the local distribution system, but will have to deal with other issues of disintegration.

A third issue is whether recent electricity prices are above or below average total costs of new plants. Suppose that a jurisdiction has a monopoly electric utility whose assets include very expensive plants, while new generation is expected to involve lower-cost facilities. This was the situation of many US utilities in the 1990s when natural gas was inexpensive, nuclear plants were problematic and coal plants faced increasing environmental protection costs. The main problem here is to compensate the utility for its "stranded costs" and to prepare consumers for lower prices ahead.

In the opposite circumstance, consider a jurisdiction with a monopoly electric utility utilising mainly low-cost hydroelectric generation where all the best sites have been used. Any

new generation will have average costs well above the existing system average cost. This would be the situation of HEPCO in 1950 or Hydro Quebec or BC Hydro today. The first problem here is to persuade the public that higher prices are a good thing because they will support new generation investment. This is a major challenge, which the Ontario government did not meet prior to restructuring. The second problem is to decide "who gets the cheap power." Simply allowing all generators to receive the market price will offer windfall gains to those owning the low-cost assets. One alternative is to offer a two-part tariff in which one block of power is sold at a low price and any additional power commands a high price. This distributes the benefits to all power users yet maintains the efficient high marginal cost price for all.

The relative costs of new and old generation may be significantly affected by the environmental policy of the jurisdiction. In much of north America coal is the lowest-cost fuel, but tough environmental regulations on the traditional pollutants have raised the cost of coal generation substantially and a serious policy to reduce greenhouse gas emissions would raise coal costs still further. Natural gas emits much less air pollution although it still emits significant amounts of CO2, so tough air pollution policies favour gas relative to coal, although they favour renewable power even more. Policies that force significant investment in renewables will increase the cost of power, since renewables are generally more expensive than fossil fuel plants.

In the UK, the Thatcher government released electric utilities from an obligation to purchase UK coal prior to restructuring, which would have allowed them to buy lower-cost imported coal. In a happy coincidence, North Sea gas came on line at the same time and low-cost and clean-burning gas captured a large market share, improving air quality and lowering prices.

A fourth issue is the extent of government involvement in the electricity sector. In Ontario the government traditionally had a close relationship with Ontario Hydro, and was accused by some of using it as a job-creation machine, rather than allowing it to focus on producing electricity at the lowest possible cost. One of the potential benefits of restructuring would be to increase the distance between the government and the utility. This is not a benefit that most governments would welcome, and it is not one that the public would easily understand if it saw the government as the instrument of ensuring that Ontario Hydro served the public interest. After all, the government had "protected" electricity consumers by freezing prices in 1993. Indeed, when the public complained about high electricity prices in 2002, the government could not resist re-involving itself in defiance of the market it had just established, indeed, despite the destruction of the market that this caused. Moreover the government could not resist intervening in the management of Hydro One when an executive's compensation was criticised. The government intervened to bar the sale of some coal-fired power plants that OPG pursued in compliance with the MPMA. The Ontario experience suggests that it should be easier to restructure in a jurisdiction in which there had been little government involvement in the past, because there is less political power to give up.

A fifth starting point is the market structure of generation and the possible market structure of generation. Without a competitive structure, the risks of market power, market manipulation and high prices are considerable. Ontario had six thermal plants that were expected to set the price much of the time. To achieve a competitive generation structure the largest of these plants must be owned or at least operated by separate firms. Not only must one

firm not operate two of them, but the operators should not compete in other markets, lest they compete less here for fear of retaliation there. With the varying size of the six thermal plants, a competitive structure is possible but not easy to achieve.

If a competitive structure will only be achieved with difficulty in Ontario, how can provinces with fewer generation plants achieve competitive structures? Given the vast geography of most provinces and the limited capacity of transmission lines, it will not be easy for generators to compete with each other. This is a substantial challenge to spreading the model of competition in Canada or elsewhere where generation plants are large and widely spaced.

A final starting point is the public's experience with fluctuating prices for other utilities and energy sources. The public in Ontario was accustomed to prices for electricity that were stable for years at a time. The last experience with rising prices was in the early 1990's when the government stepped in and imposed a price freeze. Natural gas prices had been regulated and stable until a decade or so earlier, but by 2002 the public had developed some experience with varying gas prices. Gasoline prices are unregulated and the public is used to substantial fluctuations, although they routinely complain to the government about upward fluctuations. Interestingly the increase in gasoline prices in 2005 has generated substantial public grumbling, but it has not resulted in inappropriate government actions, perhaps because there is no historic or natural role for government. So, the experience in other markets could have prepared Ontarians for varying electricity prices, but did not. One reason may have been that the public had come to expect lower prices, so upward fluctuations were seen as a breach of promise.

6. The Importance of Neighbours

As in so much of life, your neighbourhood matters for electricity restructuring. The course of electricity restructuring in a jurisdiction will be affected by several characteristics of neighbouring jurisdictions. The price of electricity in the neighbourhood relative to the home jurisdiction will have a significant impact on the enthusiasm of various stakeholders for competition. The extent to which the home jurisdiction shares an airshed with neighbours will affect the jurisdiction's enthusiasm for competition if electricity generation emits air pollutants in both jurisdictions. Finally, the extent and capacity of interties with the neighbours will affect the design of a competitive market in the home jurisdiction.

Regulated monopoly utilities are usually allowed to charge prices that will recover their reasonable costs, whatever those costs are. Suppose that the home jurisdiction has low costs and thus low regulated prices, while the neighbours have high costs and prices. Under competition, generators in the home jurisdiction will be free to sell electricity to neighbouring customers, subject to intertie capacity and to the obligation to keep the lights on at home. Neighbouring customers will be keen to purchase cheaper electricity from the home jurisdiction. Thus competition will increase exports from the low-cost jurisdiction to the higher cost jurisdiction. This will tend to raise prices in the low-cost jurisdiction and to lower them in the high-cost jurisdiction. With sufficient competition and intertie capacity prices should move close together in both jurisdictions. These effects will be welcomed by generators in the low-price jurisdiction and customers in the high-price jurisdiction while customers in the former and generators in the latter will be worse off. Before embarking on a move to competition, governments in both jurisdictions should understand the likely effects of competition on their average prices and they

should prepare their stakeholders for these effects and ensure that they have the political support for restructuring and that they have a market design that will handle the emerging economic flows and political pressures.

Ontario enjoyed prices that were generally lower than those in adjoining US states prior to market opening; indeed, Ontario prices were less than one/half the average US price until the late 1980's. It was recognised that competition might lead to prices rising to meet those in the US, so while foreign generators were allowed to bid into the Ontario market, their bids could not set the market price. Instead, the cost of the difference between the foreign bid and the market price went into the "uplift," an amount charged (or credited) to all consumers. In this way, the need to take, for example, 2% of Ontario's power from a foreign generator whose bid was 10% above the price-setting bid in Ontario would raise the market price not by 10%, but only by 0.2%.

Quebec enjoys prices that are substantially below those in Ontario, but there is little enthusiasm in Quebec for increasing exports to Ontario because the New York market will pay still higher prices. There appears to be little enthusiasm in Quebec for establishing a competitive market that would tend to force domestic prices up to Ontario or even New York levels. At present Quebec consumers benefit from lower prices and the provincial government seems happy to leave the benefits with those consumers while extracting the best possible price from exports to New York.

The home jurisdiction can regulate air pollution emissions from its own generators but usually has little influence on emissions from generators in neighbouring jurisdictions. In Canada, the dominant regulations are provincial, while in the US the federal government has managed to set standards that are applicable to many states.[16] Suppose that Ontario and Ohio both burn coal in mid-merit plants and both have similar emission rates per kWh produced. In a regulated market with monopoly utilities, both Ontario and Ohio would tend to be self-sufficient in electricity generation. If Ontario imposes strict environmental regulations on its coal-fired stations, this will raise the marginal cost of electricity from those stations, making imports from Ohio more attractive. In a regulated market, Ontario policy might dictate that imports should not increase despite the relative attractiveness of Ohio power. In a competitive market, however, the Ohio generators should be more successful in bidding into the Ontario market, given their lower costs, so imports should increase. Emissions from Ontario will be reduced both because of the lower emission rate and because of reduced utilization of the Ontario stations. Emissions from Ohio will increase, however, and the proportion of Ohio pollution that affects Ontario will offset the Ontario reduction. Thus the ultimate effect of the increased stringency of Ontario air pollution regulations is less than the initial effect calculated in the absence of an import response. More generally, it will be more difficult to control imports and exports in competitive markets than in regulated markets, so pollution control policies in one jurisdiction will have less effect than might be estimated.

In fact, the Ontario government pledged to close down all coal-fired generation in the

[16] For an overview of Canadian environmental jurisdiction see Benidickson (2002, ch. 2); for the US see Davies and Mazurek (1998, chs. 1-4.)

province by 2007 (now postponed to 2009) and has closed several stations.[17] Without adequate replacement power for Nanticoke within Ontario, it is becoming clear that imported power would yield increased pollution from the US Midwest, thus substantially offsetting the reduction from Nanticoke. The shutdown only has full effect if the power is replaced by power from a non-polluting source.

If the pollution rates are different in the home and neighbouring jurisdiction, the calculation is more complicated but the same forces are at work. Tough regulation of a dirty domestic source that led to imports from cleaner sources would yield benefits that were only modestly offset by the imported pollution. Tough regulation of an already clean source that led to imports from much dirtier sources might completely cancel out the benefits. The more closely coupled the air quality in the two jurisdictions, other things equal, the greater the offset.

Finally, competitive markets require a competitive market structure. In some cases, the generation fleet in a jurisdiction will not easily yield a competitive market structure. In such cases, we can look to imports as a possible enhancement of competition. If a neighbouring jurisdiction has several generators that could bid into the home market, and if the intertie capacity is sufficiently great, then competitive prices may be achieved even in a home jurisdiction that is not workably competitive on its own. In the case of Ontario, the MDC recommended that the interties to the US and Quebec be enhanced specifically to help reduce the market power that OPG would otherwise wield until it had substantially decontrolled.

7. Conclusions

The experience with restructuring of the electricity sector in Ontario and Alberta, when considered in the light of experience elsewhere, offers several lessons for other jurisdictions considering moving down this path. Replacing monopoly with competition in generation may lead to more efficient generation, and it may produce a spot price that can be used as the basis for marginal cost pricing of electricity to consumers. However competition also increases risks, and the system design must recognise the possibly limited risk tolerance of market participants, so that risks are shared appropriately.

Electricity markets are artificial markets with extensive rules for all participants arising from the complex interconnections of the electricity network. Governments or regulatory agencies oversee the market design process and the operation and maintenance of the market, so these are necessarily political processes. Some of the participants in an electricity market are likely to have substantial political influence. Both theory and experience provide some guidance as to the political forces that will operate on the market design and operation. The conceptual design of the market must recognise these political realities so that the political process will not thwart the intended outcome of the market. So, for example, consumers and generators must share risks sufficiently that the government will not intervene with price caps if wholesale prices exceed expectations, nor with subsidies if they fall short.

Moreover, one might be able to assess, early in the market design process, whether the political landscape will support the development of an efficient market that will serve all

[17] Press Release, June 15, 2005, "McGuinty Government Unveils Bold Plan to Clean Up Ontario's Air" http://www.energy.gov.on.ca/index .

stakeholders well. In the case of Ontario, in hindsight, we can see the lack of government will to sell off Ontario Hydro's generation plants to create a competitive structure, arising in part from the lack of public support for such a radical change from the long-standing crown corporation. There is also reason to doubt the government's willingness to distance itself from the electricity business. While the MDC worked around these problems as much as possible, another jurisdiction might postpone restructuring until there is political support for the essential steps.

The limited ability of consumers to understand changes in the electricity sector, at least in the short run, pose a real constraint on what can be achieved politically. Ontario's market design included a rebate to consumers if prices increased, yet consumers either were not aware of the rebate, could not estimate its effect on them, or were not prepared to wait until the end of the year. Either more effort should have been put into educating consumers or the refunds should have been more timely, to reduce consumer complaints which the government could not resist. It is quite possible that, after several years of experience with an electricity market, consumers would become relatively sophisticated in their understanding of it and their strategies for working with it. However stresses may arise in the short run and the market has to survive until the long-run learning can take place.

One of the challenges for electricity restructuring is that the starting points differ from one jurisdiction to another and the starting points matter. The problems are different if you begin with a crown monopoly than if you have investor-owned utilities; if expected prices are higher than recent prices rather than lower; if governments have been deeply involved in the electricity sector rather than distant from it; if the public has experience with stable electricity prices rather than fluctuating prices. Each of these has implications for the market design and for the feasibility of restructuring.

Finally, the situation in neighbouring jurisdictions matters as well. Restructuring in a low-price jurisdiction surrounded by high prices will increase the prospect of price increases at home, while a high-price island is more likely to see its prices decline. If workable competition will be difficult to achieve at home, strong interties to neighbouring jurisdictions can improve competitive performance if the market is appropriately designed. Air pollution, like electricity, moves across borders, so one must assess and evaluate the pollution implications of competition and make any appropriate adjustments to the market design.

Table 1 Effect of Wholesale Price on Ontario Residential Consumer's Bill Example, 2002				
	Consumer not signed up with a retailer			**Retail contract[5]**
Monthly average wholesale price (cts/kWh)	4.3	5.5	8.0	5.7
Wholesale Charges[1] (cents/kWh)	1.32	1.32	1.32	1.32
Transmission[2] and distribution[3] (cents/kWh)	2.38	2.38	2.38	2.38
Total of -per kWh charges (cents/kWh)	8	9.2	11.7	9.4
Total charge for 700 kWh ($)	$56.00	$64.40	$81.90	$65.80
Monthly customer charge (fixed)	$14.00	$14.00	$14.00	$14.00
GST @ 7%	$4.90	$5.49	$6.71	$5.59
Monthly bill	**$74.90**	**$83.89**	**$102.61**	**$85.39**
% bill increase from price > 4.3 cents	0.0	12.0	37.0	14.0
Rebate[4]	($1.87)	($6.37)	($15.73)	None[6]
Net cost after rebate	**$73.03**	**$77.52**	**$86.88**	**$85.39**
% net cost increase from price > 4.3 cents	0	6.2	19.0	16.9
Monthly bill for 20% more electricity	**$86.10**	**$97.67**	**$120.14**	**$99.47**
% bill increase for 20% more electricity[7]	15	16.4	17.1	16.5

1. Debt reduction charge 0.7; IMO and other charges 0.62/kWh.
2. Transmission charge 1.04 cents in 2002.
3. Distribution charges vary among municipalities; Toronto charge was 1.34 cents/kWh.
4. Assuming that the Market Power Mitigation Agreement rebate equals half of the excess of the wholesale price over the MPMA price of 3.8 cents. Including GST @7%.
5. Consumers who have signed retail contracts pay the contract price rather than the wholesale electricity price. 5.7 cents is within the range of contract prices offered in 2002.
6. Many retail contracts provide that any rebate will be paid to the retailer, not to the consumer.
7. Not considering the rebate; baseline is the same price in this column.

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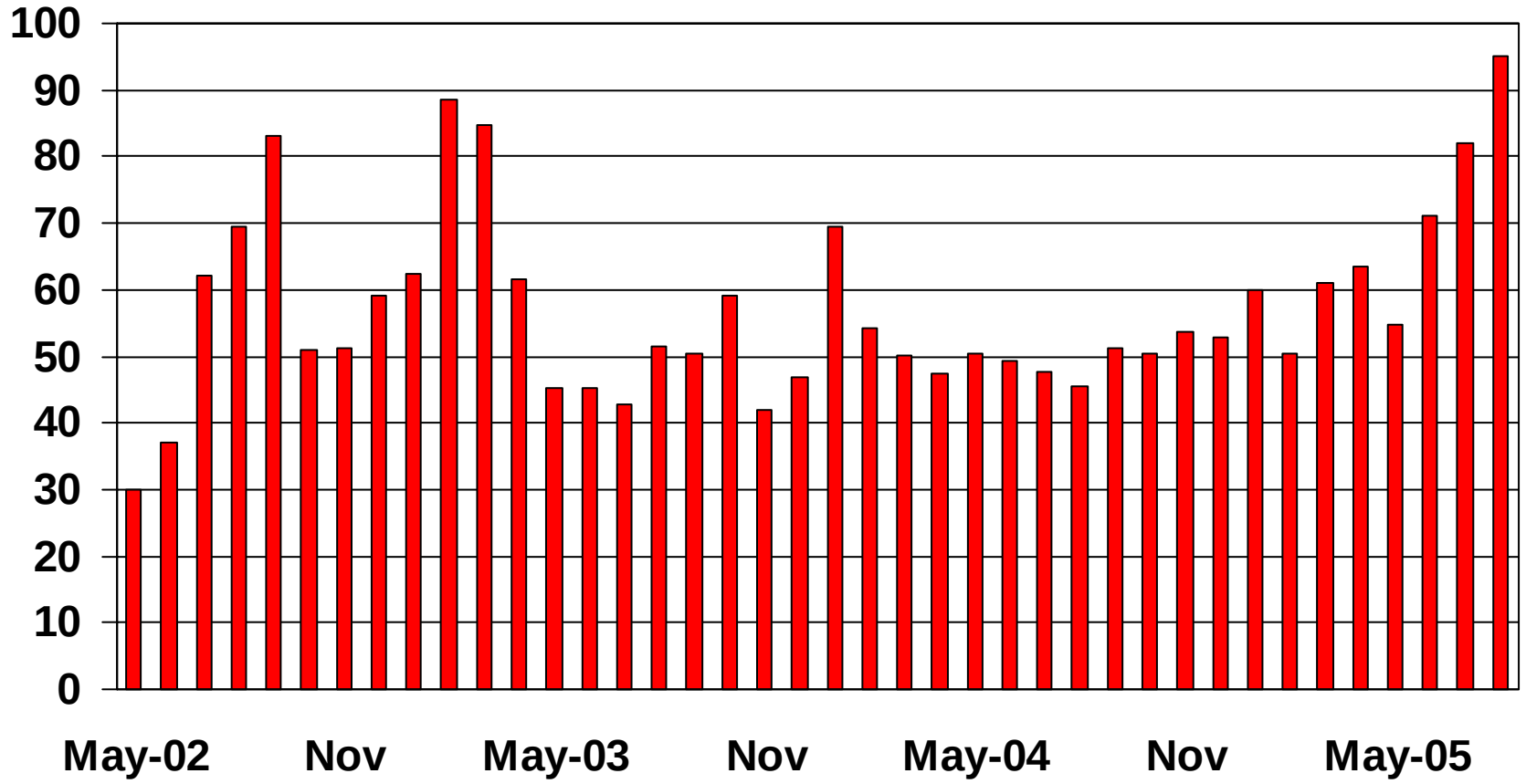
Figure 1

Hourly Ontario Electricity Price, Weighted Monthly Average
May 2002-August 2005

($/mWh)



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