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What Will Keep the Lights on in Ontario:

Responses to a Policy Short-Circuit

Michael J. Trebilcock and
Roy Hrab

In this issue...
When Ontario's electricity consumers begin to pay prices that more closely reflect market conditions, that will reduce demand and lead to more efficient use, lessening the scope and cost of new generation and transmission projects.

The Study in Brief

A cloud of confusion overhangs Ontario's electricity industry at a critical time. The provincial power system requires substantial investment in electricity generation and transmission over the next 15 years to meet increased demand. However, conflicting policies initiated by the province's former Conservative government as part of a restructuring program have sidelined potential private-sector investors. They say that the government's compromised restructuring effort makes hydro too risky a prospect to merit serious investment consideration. This *Commentary* reviews the restructuring program. Initially, the government of the day assured electricity consumers that restructuring would lead to a reduction in Ontario Hydro's swollen debt and that the entry of private-sector companies would create competition, leading to stable, and perhaps lower, electricity prices. That did not happen. After restructuring, some prices rose and potential private-sector entrants severely limited their participation in the generation market. The government responded by freezing retail electricity rates and related charges; the cost of those actions increased the hydro-related debt that was supposed to decline. The cost led the newly elected Liberal government to alter the way electricity prices are set.

The factors that led to rising prices and tight supply did not suddenly emerge after the wholesale and retail markets opened to competition in May 2002. Many were apparent years before market opening. Most importantly, the failure to significantly reduce Ontario Power Generation's dominance of the province's generation market prior to market opening reduced investor enthusiasm for Ontario's electricity market.

Private sector interest waned further following the provincial government's subsequent intervention. As a result, investments in transmission and generation will be costly, forcing the government to make trade-offs between the electricity sector and other areas, such as health care and education.

However, as Ontario's electricity consumers begin to pay prices that more closely reflect actual market conditions, that may create incentives to reduce and shift demand, as well as to use more energy-efficient products, reducing the strain on the electricity system and lessening the scope and cost of new generation and transmission projects.

The Authors of This Issue

Michael J. Trebilcock is Professor, Faculty of Law, University of Toronto. He was the Director of Research for Ontario's Market Design Committee, which was responsible for designing and recommending rules for wholesale and retail competition in the province's electricity market.

Roy Hrab is Research Associate, Faculty of Law, University of Toronto. His research interests include electricity market restructuring, alternatives to government regulation, and private delivery of public goods, including public-private partnerships and privatization.

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Ontario must develop a politically acceptable and economically feasible framework for the future evolution of its electricity market. And it must do it now. Competing in a global economy requires that Ontario possess a reliable and competitively priced electricity system. To bring long-term stability to that system, Ontario consumers will have to pay prices that reflect the actual conditions of demand and supply. Exposing them to such an environment will encourage conservation and the adoption of energy-efficient products, reducing the province's need to undertake an expensive expansion of generation and transmission capacity.

When the province's electricity market opened to competition in May 2002, electricity prices quickly became significantly higher than consumers had previously encountered. Some politicians had mistakenly told consumers to expect lower prices following market opening. In December 2002, responding to outrage at higher prices, the provincial government froze retail electricity prices, covering approximately half of Ontario's consumption, until at least 2006. The first year of the price freeze resulted in the issuance of approximately $730 million of taxpayer-guaranteed debt. The cost of the price freeze has led the newly elected provincial government to alter the way electricity prices are set. At the same time, Ontario requires billions of dollars in generation and transmission investment over the next 15 years. The need for new projects also exposes the province to significant financial obligations, requiring it to make difficult choices between financing electricity needs versus other public services, such as education and health care, or raising taxes.

The previous provincial government's creation of the Electricity Conservation and Supply Task Force in June 2003 to develop a roadmap for the electricity market's next 10-to-20 years underscores Ontario's need for concrete policy options. This *Commentary* examines the province's compromised electricity restructuring initiative and proposes a way out of the quagmire, looking at experiences in other jurisdictions that have introduced market-oriented electricity reforms.

Electricity markets are emerging as the most controversial economic sector considered suitable for privatization and deregulation, especially following the massive power blackout in the northeastern U.S. and Ontario in August 2003, with subsequent blackouts in London, England, parts of Scandinavia and Italy.

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 spheres to be natural monopolies. The government reasoned that operational and investment similarities between generation and transmission warranted the integration of the sectors.[1] As a result, many jurisdictions vertically integrated these segments into a

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1 Joskow, 1998.

government or private monopoly. To prevent the abuse of power, governments commonly imposed price controls and rate-of-return regulation.

Subsequently, many policymakers came to regard regulated monopoly arrangements as inefficient. Technological change, such as small-scale electricity generation, helped spread the idea that a market-driven electricity industry was both attainable and preferable to the regulated model. The expected gains from restructuring and deregulation are more efficient pricing and better-informed consumption and investment decisions.[2]

Despite the desire to reform electricity markets, a number of issues make deregulating and restructuring of electricity more complex than that of others, such as trucking and airlines. There are two primary problems. Failure to balance supply and demand will destabilize the entire transmission grid with service interruptions. This was reflected dramatically in the August power blackout in the northeastern U.S. and Ontario. Second, in the short-run, at peak demand times, market participants can be unresponsive to price shocks, implying that small decreases in supply or increases in demand can lead to relatively extreme price increases. Governments' inadequate handling of the potential hazards of electricity-market reform has led to spectacular failures, as in California. Because of the high costs this involves, the electricity-market reform movement's pace has significantly slowed.

The Story So Far

Prior to reform, Ontario Hydro, a vertically integrated, government-owned monopoly, was responsible for meeting the province's electricity generation and transmission needs. The power produced by Ontario Hydro was purchased and distributed to consumers by about 300 local, municipally owned utility companies, that were charged a fixed price per kilowatt hour (kWh). The bundled price included generation, transmission and distribution costs.

In 1999, Ontario Hydro had a provincially guaranteed debt of approximately $38.1 billion, or about a third of total provincial indebtedness.[3] Through the 1990s, roughly 35 percent of the utility's electricity revenue went towards paying debt interest.[4] Much of this debt was the result of over-expansion and major cost overruns in the construction of nuclear generation facilities.[5] These problems caused the price of electricity in Ontario to rise by about 30 percent in the early

2 Borenstein and Bushnell, 2000.

3 Ontario Electricity Financial Corporation (OEFC) 2000.

4 Ontario, Ministry of the Environment and Energy 2002.

5 The construction of Ontario Hydro's last nuclear station, the Darlington Station, exemplified the inefficiencies experienced under the government-owned-and-operated monopoly. The Darlington station was completed between 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. See Adams, 2000 and Trebilcock and Daniels, 2000.

1990s before a government freeze in 1993.[6] That freeze remained in place until market opening.

The poor performance of Ontario Hydro led the province to appoint an Advisory Committee in 1995 to explore the possibilities for reforming the electricity market. In 1996, the Committee's report, known as the MacDonald Report, made recommendations for realizing a more market-based electricity industry.[7] Following the MacDonald Report the government released a White Paper in 1997, proposing full wholesale and retail competition by 2000 and the division of Ontario Hydro into its generation and transmission components.[8] 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 segment.

In 1998, the provincial government formally set out the framework for the reformed electricity market in the *Electricity Act*.[9] The government then split Ontario Hydro into its transmission and generation components. In April 1999, the new state-owned enterprises, Hydro One Inc. (transmission)[10] and Ontario Power Generation Inc., or OPG, (generation) began. At this time, Ontario Hydro had $19.4 billion of debt that could not be serviced and retired in a competitive electricity market, or "stranded debt".[11]

Two agencies were mandated to oversee the electricity market: the Ontario Energy Board (OEB) and the Independent Market Operator (IMO). The primary purpose of the OEB is to regulate the monopoly segments of the electricity market by setting transmission and distribution rates.[12] The IMO controls the bulk electricity system and operates the wholesale spot market to ensure system reliability; its independent Market Surveillance Panel monitors market power abuses.

To discourage OPG from using its dominant position to exercise market power in generation markets, the organization entered a Market Power Mitigation Agreement (MPMA) with the provincial government.[13] The MPMA mandated that OPG must pay a rebate to consumers on 90 percent of its domestic sales where the wholesale price exceeded 3.8 cents per kWh.[14] The MPMA also required OPG to decontrol 65 percent of its price-setting and base-load facilities over a 10-year

6 Trebilcock and Daniels, 2000.

7 Ontario, 1996.

8 Ontario, 1997.

9 *Electricity Act*, 1998, S.O. 1998, c. 15, Sch. A.

10 The transmission firm was originally called the Ontario Hydro Services Company. The company was renamed Hydro One Inc. on May 1, 2000

11 OEFC, 2000.

12 The OEB also licenses all electricity market participants including generators, transmitters, distributors, wholesalers, retailers and the IMO, and is required to approve amalgamations, mergers, acquisitions and divestitures of distributors, and as well as transmission-line construction.

13 Trebilcock and Daniels, 2000.

14 Goulding et al., 2001.

timeframe following market opening.[15] In complying with the MPMA, OPG leased its Bruce nuclear power plants to the private sector in May 2001 and sold four price-setting hydro-electric plants situated on the Mississagi River in March 2002.[16] OPG currently controls between 70 and 75 percent of the province's generation capacity.

Hydro One also undertook to try to increase inter-tie capacity with neighboring jurisdictions in Canada and the U.S. by 50 percent within three years of market opening.[17]

At market opening, the province unbundled electricity prices into separate components, such as transmission charges, energy charges and distribution charges. In order to finance the stranded debt of Ontario Hydro, the province assessed consumers a 0.7 cent per kWh debt retirement charge (DRC). At the end of March 2002 the value of the stranded debt was $20.1 billion.[18]

Opening the Market

In April 2002, the month before market opening, the IMO's 10-Year Outlook (2003-to-2012) stated that "[b]ased on existing and proposed facilities, Ontario is expected to have reliable supply of electricity for the 10-year period under a wide variety of conditions."[19] During April, the province's attempt to privatize Hydro One was blocked by a court challenge.[20]

Ontario's electricity market opened to both wholesale and retail price competition on May 1, 2002, market opening was originally scheduled for November 2000.[21] In the open wholesale market, the marginal supplier sets electricity spot prices every five minutes in response to changing levels of demand and supply. Participation in the wholesale market is voluntary; wholesale

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15 Ibid. OPG was required to divest 65 percent of its price-setting generating units within the first three-and-a-half years after market opening, and 65 percent of its core, or base-load, facilities within 10 years of market opening. Price-setting, or marginal , units are the units that are brought on- and off-line as needed to meet peak load requirements, while core-, or base-load units operate more or less continuously.

16 "Brascan buys four hydro stations from Ontario: 490 megawatts 'decontrolled,'" *Canadian Press Newswire*, (March 8, 2002).

17 Trebilcock and Daniels, 2000.

18 OEFC, 2002.

19 IMO, 2002b.

20 On December 12, 2001, the province announced its intention to sell Hydro One through an initial public offering (IPO). Notably, the Power Workers' Union supported the privatization effort, arguing that immediate investment was required to modernize the transmission grid. However, two other unions challenged the privatization of Hydro One, alleging that the Electricity Act did not authorize the provincial government to sell the company's assets. On April 19, 2002, Mr. Justice Arthur Gans ruled in favour of the union's challenge, stating that if the purpose of the *Electricity Act* was to privatize Hydro One then this "should have been set out in clear and unequivocal terms in the 'purposes' portion of the *Electricity Act*." On January 20, 2003, the province announced that it would retain 100 percent ownership of Hydro One.

21 Market opening was 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.

consumers may directly enter bilateral volume or financial contracts with wholesale sellers and generators. Retail-market consumers were free to enter fixed-price contracts with retail intermediaries. Almost one million of the province's estimated 4.4 million electricity customers took out fixed-price contracts with retail intermediaries.[22] Consumers not establishing a relationship with a retailer purchased electricity through their local distribution utility which passed through the spot-market price.

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. Prices began to increase rapidly as the abnormally hot summer progressed. In July, the average hourly energy price was 6.2 cents. The highest hourly price recorded was $1.03 per kWh ($1028.42 per MWh) during hour 14 of September 3.[23]

From July through September, the IMO issued both power warnings and power advisories, requesting consumers to reduce usage because power supplies were under strain.[24] In October 2002, the IMO said "[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, 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."[25]

And Closing the Retail Market

In response to mounting criticism of the high summer electricity prices, on November 11, 2002, the province announced it would rebate consumers for the high prices of the summer and freeze retail prices.[26]

On December 9, 2002, the *Electricity Pricing, Conservation and Supply Act*, 2002 became law.[27] The legislation lowered and froze the retail price of electricity for

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22 "Ontario government moves killed energy retailing, say executives," *Canadian Press Newswire*, (November 13, 2002).

23 IMO, http://www.theimo.com/imoweb/marketdata/marketSummary.asp

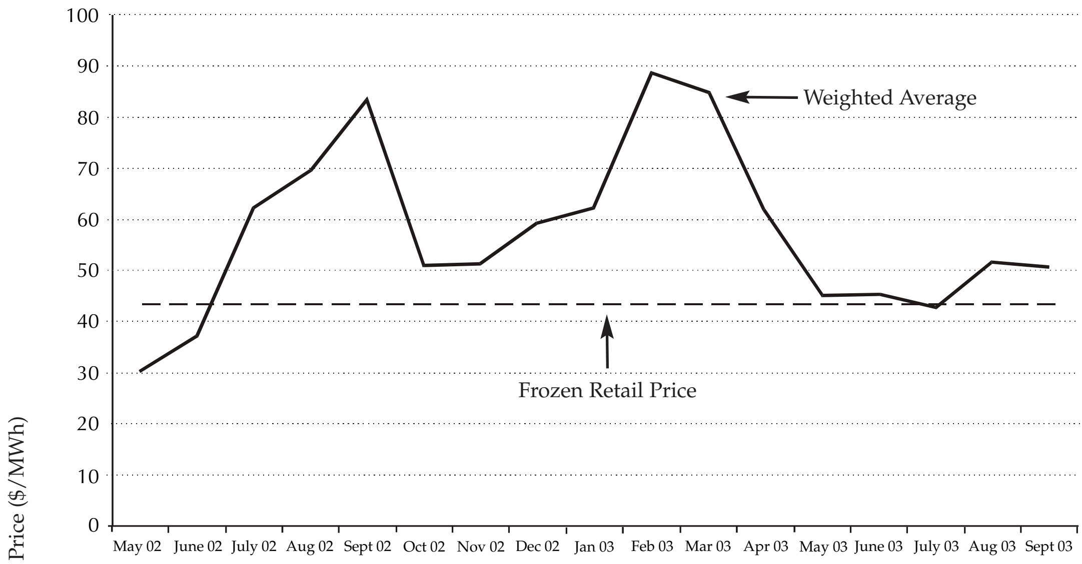
24 IMO, http://www.theimo.com/imoweb/news/media.asp. According to the IMO: "Power Warnings are issued by the IMO when supplies of power may not meet demand. Current system conditions mean the IMO may need to take protective actions and reduce demand including, but not necessarily limited to, voltage reductions." In contrast, "[t]he 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." During 2002, power advisories were issued by the IMO on July 29, August 12 and 14, and September 9 and 20. Power warnings were issued on July 2 and September 10.

25 IMO, 2002a.

26 Ontario, Ministry of Energy, *Action Plan to Lower Your Hydro Bill*; "Eves promises legislation to cap cost of hydro on Dec. 1 and provide rebates," *Canadian Press Newswire*, November 11, 2002.

27 *Electricity Pricing, Conservation and Supply Act, 2002*, S.O. 2002, c. 23.

Figure 1: *Ontario Wholesale Electricity Spot Prices (May 2002-September 2003)*



Source: IMO

low-volume[28] and other designated consumers[29] at 4.3 cents per kWh, and included consumers who had signed fixed-price contracts with retailers. The freeze is estimated to affect about half of the electricity consumed in the province. The government made the frozen retail rate retroactive to market opening, refunding any amount over 4.3 cents that consumers had already paid.[30] In March 2003, the province extended the frozen retail price to consumers using less than 250,000 kWh per year (approximately an additional 7,000 consumers).[31]

The government said it would freeze the retail price until at least 2006 and "will continue until there is a sufficient electricity supply, at reasonable prices, to meet Ontario's long-term needs."[32] It also placed limits on all energy rates, including transmission, distribution, wholesale market, uplift and customer charges.[33] The wholesale market and customer charges are under review. Only wholesale prices remain determined by market forces. The energy minister now oversees the creation of market rules and approves changes to transmission and distribution rates.

28 Lower volume consumers are those using less than 150,000 kWh per year, such as households, small businesses, and farmers.

29 Other designated consumers are municipalities, universities and colleges, public and private schools, hospitals and registered charities.

30 Ontario Ministry of Energy, 2002.

31 "Eves government announces Business Protection Plan for large electricity consumers," *Canada Newswire,* (March 21, 2003); "Ontario rejects pleas for major expansion of electricity price cap," *Globe and Mail*, (March 22, 2003), p. B3.

32 Ontario Ministry of Energy, 2002.

33 Ibid.

Figure 2: *Average Hourly Ontario Prices Relative to Neighbouring Control Areas, Off Peak*

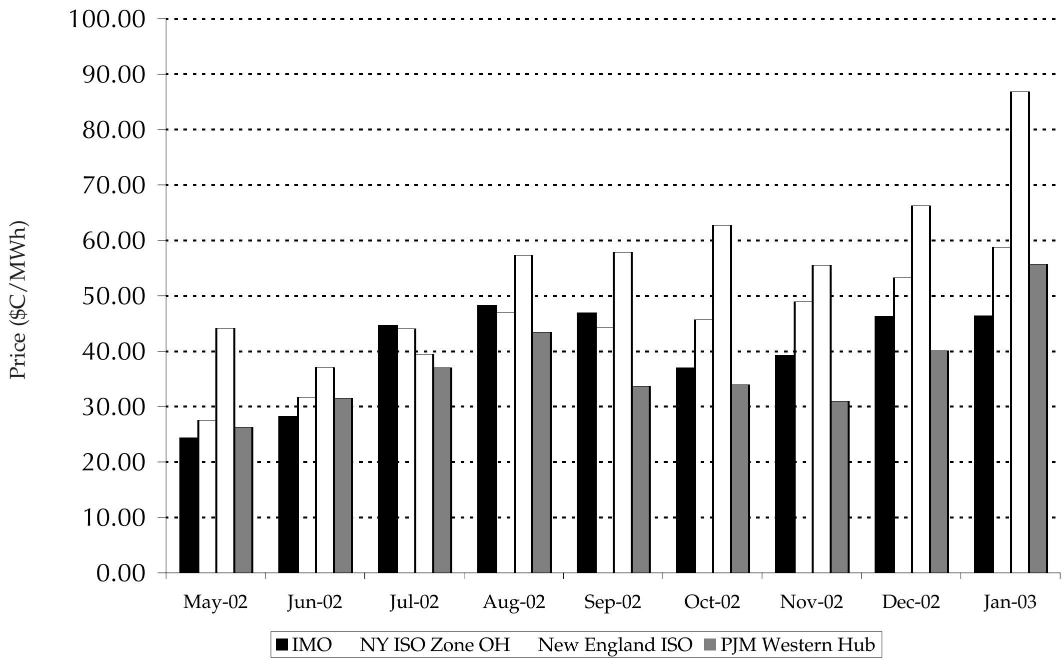
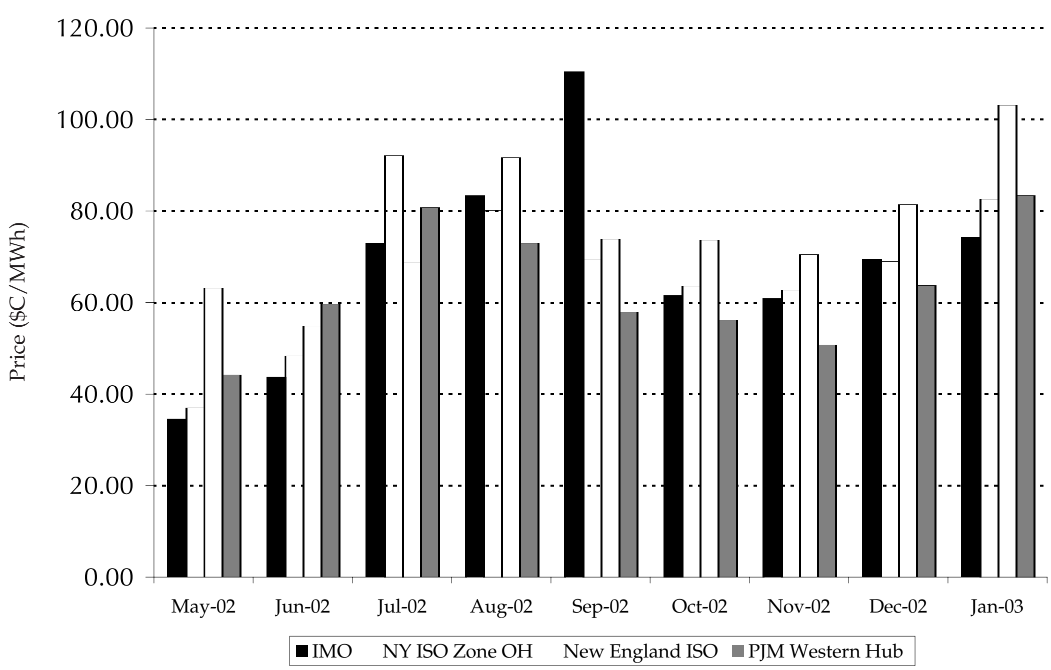


Figure 3: *Average Hourly Ontario Prices Relative to Neighbouring Control Areas, On Peak*



The weighted average price for the first year of the open market was 6.2 cents per kWh.[34] The average monthly prices from May 2002 to September 2003 are depicted in Figure 1.

The IMO examined the Ontario market to determine whether generators had abused market power during the summer of 2002.[35] After looking at almost all high-priced hours — all hours where the price exceeded $200/MWh — it found no evidence of abuse. An analysis of the September 2002 through January 2003 period also found no abuse.[36]

As well, while the price of electricity in Ontario during the summer of 2002 was significantly higher than the previous frozen rate, Ontario prices did not vary significantly from those of neighboring jurisdictions. In fact, Ontario electricity prices almost never exceeded those of neighboring jurisdictions (Figures 2 and 3).

A Crisis in the Making

Some politicians and other observers argue that Ontario's problems are an inevitable result of privatization and deregulation.[37] Such an outright rejection of electricity market reform is unwarranted because extremely limited privatization and deregulation occurred in Ontario. However, the evidence does indicate that the lack of commitment towards restructuring exhibited by the previous provincial government contributed to the tight supply-demand situation and to the volatile prices experienced in 2002. A reduction in domestic generation capacity, an increasing reliance on imports, limited import capacity, and extreme temperatures all helped send prices higher. These developments did not suddenly emerge in the summer of 2002; most were apparent years before Ontario's market opened to competition.

Supply and Demand — Out of Sync

The Market Surveillance Panel of the IMO conducted an analysis of the Ontario wholesale market for the May-through-August 2002 period, concluding 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."[38] Also contributing to the imbalance of 2002 was a decrease in provincial generation capacity and limited transmission

34 IMO, 2003d.

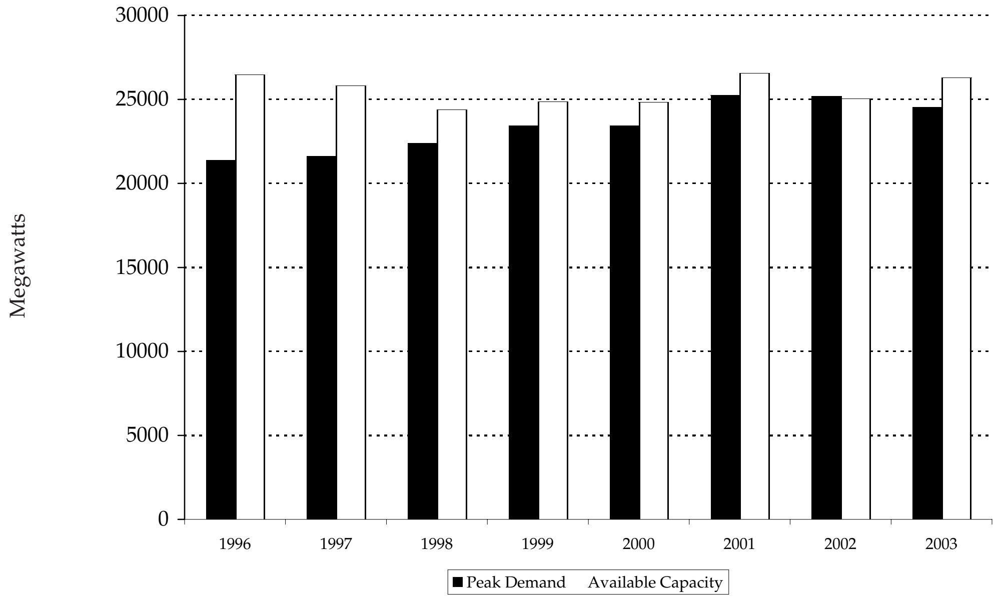
35 IMO, 2002a.

36 IMO, 2003b.

37 Hampton, 2003.

38 IMO, 2002a. The nuclear outage was caused by damage to the 840MW Bruce Power Unit 6 nuclear generator. Unit 6 was on a planned outage for maintenance purposes beginning in March 2002, and was scheduled to be operational by July 2002. However, the unit was damaged during maintenance, delaying its return to service until late August 2002. The Market Surveillance Panel conducted an investigation into the outage, finding no evidence of market- power abuse. See IMO, 2003a.

Figure 4: *Peak Summer Demand vs. Available Capacity in Ontario, 1996-2003*



capacity to import electricity. Both of these factors were known years before market opening.

During the summer of 2002, the demand for electricity exceeded available capacity at peak times (Figure 4). 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 percent in 1996 to -1.5 percent in 2002."[39] The increased summer demand — the peak demand was 25,414 MW on August 13, 2002 — and diminished hydroelectric capacity were primarily caused by above-average summer temperatures. The heat increased demand for electricity for air-conditioners and reduced the amount of water available for hydroelectric generation. From 1984 to 2001, the average annual growth of primary energy demand in Ontario was 1.6 percent.[40] During the first year of the open market Ontario experienced a demand increase of 5.5 percent.[41]

A major cause of the capacity deficiency was a substantial amount of nuclear power generation taken offline for reliability and safety reasons, with little new generation capacity built. In 1993, in an effort to stabilize Ontario Hydro's financial outlook, the provincial government directed the cancellation of a number of planned and in-progress generation projects.[42] Between 1995 and 1998, the 3300 MW Bruce Nuclear Power Station-A (Bruce) was taken offline. In 1997, the 2060 MW Pickering Nuclear Power Station-A (Pickering) was removed from service.

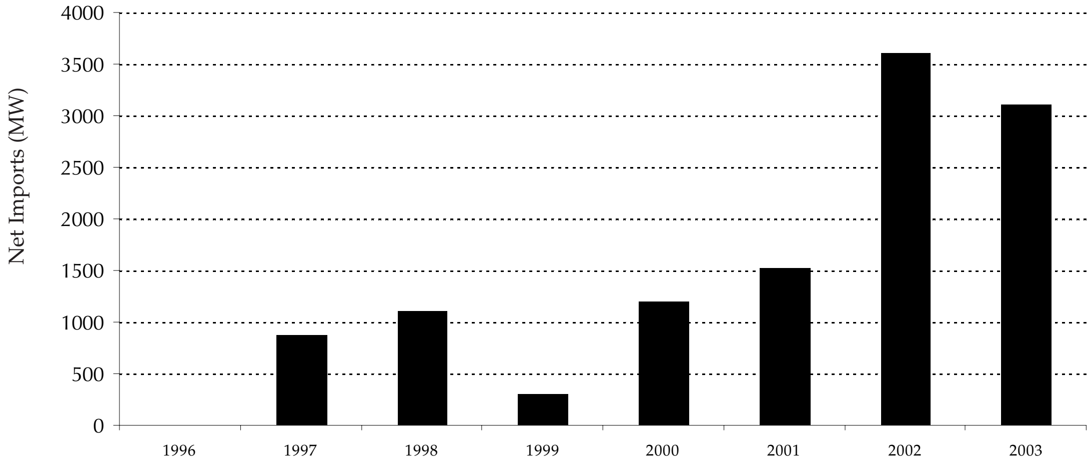
39 IMO, 2002s, p. 132.

40 IMO, 2002c.

41 IMO, 2003d.

42 Hampton, 2003.

Figure 5: *Net Imports for Summer Peak Hours in Ontario, 1996–2003*



However, in late 1998, Ontario Hydro announced plans to investigate the restart of the Pickering units for the winter of 2000/2001.[43] The restart experienced numerous delays and substantial cost overruns, apparently due to safety and technical issues.[44] The estimated cost of the restart has risen from $800 million to over $2.5 billion.[45] The first Pickering unit to restart did not begin producing electricity until August 2003. There is no timetable for restarting the remaining three reactors. In fact, depending on the results of a review, the remaining units may not restart.[46] Had the Pickering units restarted as originally planned, the price increases and volatility experienced during the summer of 2002 would have been mitigated partially; however, the Pickering delays were known prior to market opening.

The lack of available domestic generation capacity have forced Ontario to import electricity to balance supply and demand during the summer since 1997 (Figure 5). The IMO made 38 emergency import purchases during the summer of 2002 to maintain system reliability.[47] The large amount of imports strained

43 "Hydro allots $50 million for possible Pickering restart," *Toronto Star*, (October 26, 1998), p. A4.

44 In 2001, the station's first unit was expected to restart by mid-2002. In October 2002, it was announced that the first unit would become operational in mid-2003 and the last unit by 2005.

45 "Pickering reactor restart cost climbs $60M," *Toronto Star*, (April 8, 2003), p. E1. The cost of constructing the Pickering A station in 1971, adjusted for inflation, was approximately $3.2 billion.

46 On May 30, 2003, the province announced that an inquiry into the Pickering restart would be held. The review will make an assessment regarding the feasibility and cost-effectiveness of restarting the remaining three reactors following the restart of the first unit. The review team will present its final report in December 2003.

47 IMO 2002a.

transmission inter-tie capacity 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 of 2002.[48] The province was importing the maximum amount of electricity — roughly 4000 MW — that the transmission system could physically accommodate. The peak amount scheduled for import was 4273 MW on September 20, 2002.[49]

By 2002, Hydro One anticipated phase-shifting transformers to be operational at the Michigan inter-tie, which would increase import capacity by 500 MW. However, the transformers experienced significant technical difficulties and were not available for the summer of 2002. The transformers are now expected to come into service in 2004. A lack of investment in the province's transmission network also contributed to the strain on the system's inter-ties. Much of the province's transmission grid was installed in the 1960s, with some of it dating back to the 1940s.[50] In April 2002, the month before market opening, the Power Workers' Union said that the Ontario grid needed to expand transmission links with neighboring jurisdictions and did not oppose privatization of the grid.[51] However, prior to market opening, Hydro One spent approximately $500 million acquiring local distribution companies. Arguably, the resources used to acquire LDCs would have been better used on transmission grid improvements and paying down Ontario Hydro's stranded debt.

Reluctant Investors

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, only two new private-generation projects became operational during the first year of the open market: TransAlta Corp.'s 575 MW co-generation plant in Sarnia and Brascan Corp.'s 45 MW hydroelectric generator near Wawa.[52] There are a number of reasons for this limited private sector interest, many of which were known long before market opening.

Industry participants cited the delay in market opening and uncertainty over the final rules governing the market as factors contributing to the failure of the province to attract private investment. Specifically, if market opening had occurred in 2000 as originally planned, the crises of 2002 may have been partly avoided. The delay was costly because investors lost confidence in the electricity sector following the California crisis in 2000/2001 and the collapse of Enron in 2001/2002. As a result, investors who may have put funds into generation capacity in 2000 came to

48 Ibid.

49 Import and Export data available on the IMO website: http://www.theimo.com/imoweb/marketdata/marketSummary.asp.

50 "Power union supports Hydro One bid for privatization: Systems needs an upgrade," *National Post*, (April 23, 2002), p. FP1.

51 Ibid.

52 IMO 2003d.

view the North American electricity market as too risky and were no longer interested — or were unable to raise sufficient capital for new generation capacity — when the Ontario market opened.

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 industry because of continued OPG ownership and control of generation assets and the prolonged decontrol timetable.[53]

In 2000, OPG owned and controlled approximately 90 percent of the province's capacity and the provincial government did little to allay investor concern regarding its dominance. In fact, the provincial government sometimes contributed to undermining investor confidence. For example, the announcement of restarting Pickering nuclear units — and in the process, increasing OPG's generation capacity — in 1998 further discouraged private investment. Additionally, in 2000, the province placed a temporary freeze on the sale of OPG's coal-fired generation plants, citing the need for environmental safeguards prior to privatization.[54]

OPG's ownership and control of generation assets 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. White (1996) argues that through long-term bilateral contracting, companies wanting to enter the generation market will have a secure future revenue stream, mitigating sunk-cost problems and enabling them to obtain project financing.[55] Some large-scale generation investment projects require 20-year payback periods. The lack of interest in forward contracts was evident from the fact that about 60-to-70 percent of electricity was purchased in the Ontario spot market during the summer of 2002.

OPG's lease and sale of generation assets during 2001 and 2002 occurred too late to influence Ontario's generation capacity when the market opened. Investor reluctance between 1998 and 2000 meant that substantial new operational private generation by market opening was unlikely because some large-scale projects require three-to-five years to finance, construct and obtain necessary regulatory approvals, including environmental assessments, before entering service.

Some industry participants argue that market rules discourage investment in the province because the price of imported electricity does not set the market clearing price. 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-

53 "New competitors shy of Ontario hydro market," *Financial Post*, (August 21, 1998), p. 5; "Hydro sale plan takes too long, group says," *Toronto Star*, (October 15, 1999).

54 "Sale of coal-fired plants on hold pending review," *Toronto Star*, (May 18, 2000), p. A9.

55 White, 1996.

province generators received $2 per kWh for electricity while Ontario generators were receiving 47 cents per kWh.[56]

Assessment of Ontario Policy

The facts that we have outlined illustrate that a lack of political will to restructure the province's electricity sector led to the high prices experienced during the summer of 2002. The provincial electricity system's ability to satisfy unanticipated supply and demand shocks had been deteriorating for years prior to market opening. Ontario did not have to freeze retail electricity prices and cancel plans to privatize electricity assets. A number of alternative courses of action were available to the provincial government prior to, and following, market opening that would have better addressed the electricity needs, as well as consumer and investor concerns.

For one thing, the provincial government could have been more active with respect to privatizing assets in the years prior to market opening in order to improve the environment for private investors. The government could have divided OPG into a number of separate companies and privatized them. Instead, it precluded the Market Design Committee from making such a recommendation. The privatization of Hydro One could also have occurred. Instead, the provincial government did not announce its intentions to privatize the transmission grid until December 2001, less than a year before market opening.[57] The delay in market opening provided the government with an opportunity to address private-sector concerns; still, despite the knowledge that domestic capacity had decreased and that private investment was not occurring, little was done to improve the investment climate. Not only that, during the summer of 2002, investor confidence was undermined when the province blocked the sale of two OPG coal-fired generating plants.[58] Then, the province cancelled its plans to privatize Hydro One. Such actions indicated that Ontario was not committed to restructuring or to a competitive generation market. Because of the government's actions it may be argued that Ontario would be better off, in terms of generation capacity, had the flawed restructuring process never occurred. This argument gains strength from the fact that during restructuring, the government committed to building no generation capacity, with the exception of the Pickering restart, while discouraging private investment, resulting in almost no new capacity coming online between 1998 and 2002.

The government could have made a stronger and more compelling case for deregulation and restructuring. The province could have clearly stated that electricity prices in Ontario had been capped at a level below cost for years, emphasizing that the initial gains from restructuring would come from reduced

56 "Price gap discourages Ontario generators," *Toronto Star*, (August 10, 2002), p. C1.

57 "$10B power giant up for sale," *Toronto Star*, (December 13, 2001), p. A1.

58 "Ontario blocked sale of coal-fired plants: Industry questions commitment to creating market," *National Post*, (November 4, 2002), p. FP2: It was reported that a spokesman for the Minister of Energy stated that the sale price "did not meet our standard of ensuring maximum value for Ontario taxpayers and electricity consumers," and that the buyer would not commit to convert the plants to natural gas facilities.

government debt through the sale of assets, and that over the long-term, competition would lead to lower prices or lower price increases. Instead, despite the reduction in domestic capacity, Pickering restart delays and an increase in imports leading up to market opening, some politicians and industry participants told consumers that the province would have a large surplus of generating capacity and that there would be no price spikes following market opening.[59]

At the same time, consumers were not well informed about the OPG rebate mechanism. If they had been more aware that they would be receiving a rebate from OPG at the end of the year, there would have been less public outrage over rising prices. The IMO estimated that the OPG rebate would have reduced the average electricity charge from 6.2 cents per kWh to approximately 5 cents per kWh for the first year of the open market.[60] Payments of the rebate could have been accelerated to occur on a quarterly or monthly basis. These steps would have mitigated consumer concerns about higher prices, reducing political pressure to freeze rates. On March 21, 2003, the province belatedly announced that consumers using more than 250,000 kWh a year would receive OPG rebates quarterly, rather than annually, with the rebate fixed at 50 percent of the value by which the average wholesale price exceeds $38 per MWh.[61]

As well, 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. The province could have unbundled electricity charges prior to market opening, enabling consumers to make realistic comparisons between offers from competitive retailers and the standard supply offer of the LDCs.

Rather than adopting these initiatives, Ontario pursued policies that exposed the province to a potential electricity and financial crisis. In fact, Ontario would probably be better off, in terms of generation capacity, under the Ontario Hydro monopoly than under the present supply situation caused by the government's actions leading up to, and following, market opening. However, even with an intact Ontario Hydro, the problems of fiscal sustainability and a lack of demand responsiveness remain.

There are three primary results of the province's retail price freeze and retreat from restructuring: Substantial financial obligations by the province; an elimination of incentives to reduce electricity consumption, and a lack of incentives for investment in new generation and transmission by the private sector.

The Government's Financial Exposure

Growing electricity demand, an absence of privately financed generation and increasing electricity prices will necessitate larger contributions from the government to finance the electricity network. If this situation is not corrected, the

59 "Power: It's open market on May 1," *Toronto Star*, (December 19, 2001), p. A1.

60 IMO, 2003d.

61 "Eves government announces Business Protection Plan for large electricity consumers," *Canada Newswire*, (March 21, 2003).

probable result will be a downgrading of the province's credit rating, leading to higher borrowing costs for the government. To finance the electricity market without moving to a market-based pricing regime, Ontario can either reallocate funds from existing public services, such as education or health care, requiring trade-offs between competing objectives to be made now; incur substantial new debt, delaying the trade-off choices to the future; raise taxes, or increase the debt retirement charge for electricity ratepayers. The government should present the citizens of Ontario with these clear choices.

The retail price freeze exposed the province to significant financial commitments. The costs of the freeze are paid for out of OPG's fund for rebates of revenues in excess of its 3.8-cent wholesale price cap and by the Ontario Electricity Financial Corporation. The OEFC is a government agency created by the provincial government to manage the provincially guaranteed debt and other legacy liabilities of the former Ontario Hydro. Under the previous provincial government, the Ministry of Energy stated that the price freeze would be "revenue neutral," claiming that the program would "pay for itself" when wholesale prices fall below the frozen retail price.[62] There is no evidence to support this claim. During the first year of the price freeze, the OEFC was required to finance approximately $730 million of the costs of the freeze. OEFC debt is guaranteed by Ontario taxpayers. The newly elected government will alter the 4.3 cents per kWh frozen rate. Under the government's interim plan, beginning April 1, 2004, those covered by the current freeze will pay 4.7 cents per kWh for the first 750 kWh of consumption per month and 5.5 cents per kWh for additional consumption. This price regime will be less costly to maintain than the current price freeze.

An additional consequence of the closing of the retail market, the freezing of energy rates and failure to privatize the assets of OPG and Hydro One is that major credit rating agencies have downgraded or issued negative outlooks for OPG, Hydro One and "all rated provincial and municipal government-owned electricity utilities in Ontario."[63] Credit downgrades will increase the costs of borrowing for these companies, adding to the substantial electricity debt incurred by Ontario Hydro. Eventually, this debt will have to be paid for by electricity consumers through higher rates, or by taxpayers through higher taxes.

The retail price freeze created incentives for the provincial government to prevent further OPG decontrol. Further decontrol by OPG would decrease the amount of rebates that it is required to pay, increasing the government's direct financial exposure through higher debt of the OEFC. The new provincial government has pledged that it will not sell any publicly owned generation assets. It is studying a number of multi-billion-dollar generation and transmission expansion projects that threaten to substantially increase the government's financial commitments to the electricity sector.

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62 "Rebate plan hit by frigid winter Hydro freeze costing millions," *Toronto Star*, (January 29, 2003), p. A1.

63 "Ontario utilities put on credit watch as energy minister pleads for patience," *Canadian Press Newswire*, (November 13, 2002); "Credit alarm sounds for Hydro One: 'Significant uncertainty': Rating agencies say cost of raising cash could increase," *National Post*, (June 8, 2002), p. FP3.

Sidelining Investors

The previous government's interventions, future governments' potential interference and the unresolved issue of OPG's market dominance are creating significant pricing and regulatory concern. In the event of extreme weather, Ontario may face capacity shortfalls over the next few years.[64] The MPMA rebate and frozen retail prices significantly reduce the incentive for consumers to enter into long-term contracts, jeopardizing the province's future generation capacity by discouraging private investment in new generation facilities. Moreover, the IMO estimates that 20 percent of existing generation capacity will be "retired from service or require substantial refurbishment over the next 10 years, with another 20 percent in the subsequent five years."[65] Almost all existing generation capacity will be retired from service or require substantial refurbishment over the next 30 years.[66]

Since discussion and implementation of the retail market price freeze, nearly all of the new generation planned has been delayed or cancelled. For example, in November 2002, Sithe Energies Inc. suspended plans to construct two power plants with a combined capacity of nearly 1700 MW; the plants, which had obtained the necessary regulatory approvals, could have been online by 2005.[67] The reasons for delaying construction included OPG's market dominance and the potential for government interference.[68] In March 2003, the IMO reported that only about 2200 MW of approximately 8800 MW of planned generation was under construction.[69]

Actions by the previous Conservative provincial government have contributed to waning private-sector interest in Ontario's generation sector, while exposing the province to financial obligations far in excess of the direct costs of the retail price freeze. For the summer of 2003, the province contracted with private generators to provide extra power at an estimated cost of $70 million.[70]

The costs of larger-scale generation projects are substantial. In June 2003, the provincial governments of Ontario and Manitoba announced that they would investigate the possibility of jointly financing the construction of a $5 billion, 1250 MW hydro-electric station on the Nelson River.[71] If that project is undertaken it would not become operational until 2010, at the earliest, and would also require a new transmission line, costing $1.4 billion[72] In August 2003, the previous Ontario

64 IMO, 2003e.

65 IMO, 2003c.

66 IMO, 2003d.

67 "Sithe puts off power project, blames capacity sales rules: Two plants could have supplied 1.7 million people," *National Post*, (November 30, 2002), FP12.

68 Ibid.

69 IMO, 2003c.

70 For the summer of 2003, the province contracted for 267 MW of temporary natural-gas powered generation; the province also contracted with existing private generators to make approximately 170 MW of power available during peak demand times. The temporary generators are to remain installed until early 2004. See: "Eves government selects temporary natural gas generators for prudent electricity reserves," *Canada Newswire*, (June 3, 2003); "Third of emergency electricity supply deals fall through," *Toronto Star*, (July 22, 2003), D1.

71 "PM touts Manitoba dam to Eves: $5B hydro project," *National Post*, (November 27, 2002), p. A4.

72 Ibid.

government announced it was studying a $2 billion, 900 MW expansion of OPG's Sir Adam Beck Generating Station at Niagara Falls.[73]

As well, the Progressive Conservative government instructed OPG to develop public-private partnerships to build new generation capacity and actually entered a partnership with TransCanada Pipelines Ltd. to build the 550 MW Portlands Energy Centre in Toronto (the project is currently undergoing environmental assessment).[74]

Private sector participation in the province's transmission grid is unlikely. A planned 975 MW merchant transmission line with Pennsylvania through Lake Erie was halted in November 2002 because of the financial uncertainty surrounding such companies following the Enron scandal and policy reversals in Ontario.[75] A merchant transmission line is a commercial investment in transmission with a rate of return determined by market dynamics.[76]

The previous provincial government was also considering a second transmission-expansion project, in addition to the Manitoba proposal.[77] In July 2003, Ontario and Quebec renewed discussions regarding the construction of a $300 million, 1500 MW transmission line between the two provinces; if approved the line is expected to take two years to construct.[78]

These actions further discourage private investment in the Ontario electricity market, creating the need for additional government intervention and greater financial commitments that will be paid for by taxpayers and electricity ratepayers.

Unrestrained Consumption

The retail price freeze is exacerbating the supply-demand imbalance in Ontario's electricity market. Previously, increasing retail prices indicated that supply was tight relative to demand, signaling consumers to reduce their use or face an increased electricity bill. However, frozen retail prices eliminate consumers' incentives to limit demand in times of tight supply or shift consumption to off-peak periods, with the result that demand is now unresponsive to changes in the wholesale price. Thus, an expected result of the retail price freeze is higher wholesale prices. Furthermore, because about half of the province's total demand is now unresponsive to price, the province requires a larger amount of generation and transmission capacity to meet peak demand.

73 "Feasibility study ordered for Beck 3 project," *Niagara Falls Review,* (August 29, 2003), p. A1.

74 Portland Energy Centre website: http://www.portlandsenergycentre.com/.

75 "Huge Hydro One project halted: Critics blame Ontario's reversal on deregulation," *National Post*, (November 15, 2002), p. FP1.

76 See http://www.ksg.harvard.edu/hepg/Merchant_transmission.htm. Merchant transmission is defined by the Harvard Electricity Policy Group as: "Commercial transmission investments made in response to market-based incentives. The return on investment depends on a combination of sales of transmission rights or profits from locational arbitrage of energy prices. The investment does not add to a regulated rate base or qualify for a regulatory recovery mechanism. The full market risk and reward accrue to the transmission investors."

77 "PM touts Manitoba dam to Eves: $5B hydro project," *National Post*, (November 27, 2002).

78 "Quebec ready to support Ontario," *Toronto Star*, (July 9, 2003), p. A6.

Policy Options

This section discusses a set of options available to Ontario to ameliorate the electricity and financial problems created by the previous government's policy regime. Coincidentally, the IMO's Market Evolution Program is currently studying a number of policy options for the Ontario electricity market, including some discussed below.[79]

Restructuring

The division of the electricity market into its separate components is a standard element of most restructuring initiatives. In the case of state-owned monopolies, this involves the de-integration and privatization of the generation, transmission and distribution segments of the industry. Ontario engaged in minimal industry restructuring beyond de-integration. Both Hydro One and OPG remain government-owned enterprises. OPG still dominates the generation sector. There are as many as 95 distribution companies comprised of Hydro One and local distribution companies independently owned by municipalities.[80] The new provincial government says that it will not sell any publicly owned electricity assets, such as transmission and generation facilities.

The international experience and the present perceptions of the Ontario public regarding deregulation and restructuring offer a number of potential policy options. First, Ontario should investigate the consolidation of some of its LDCs; such a strategy may foster a better environment for the use of forward contracts. Yatchew (2001) estimates that while distribution companies exhibit increasing returns to scale, efficient scale of operation is reached even by relatively small distributors, with 20,000-to-30,000 customers.[81] Currently, 50 percent of Ontario's LDCs, on average, serve less than 5,000 customers each.[82]

Second, Hydro One should be prevented from acquiring more LDCs. While it remains publicly owned, Hydro One should direct its resources to upgrading and enhancing the province's transmission grid, and paying down Hydro debt. Littlechild and Yatchew (2002) argue that Hydro One's continued ownership of distribution assets may create many problems. These include the distortion of capital investment decisions for the transmission and distribution systems, the creation of possibilities for cross-subsidization between transmission and distribution, and the complication of regulatory oversight.[83] An LDC consolidation plan would require Hydro One to divest many LDCs to regional utilities in contiguous areas.

Third, and most importantly, if the provincial government wishes to restructure and deregulate in the future it should commit to a decontrol program by setting a

79 The IMO's Market Evolution Program can be accessed at: http://www.theimo.com/imoweb/consult/marketDev.asp

80 Distributors' Electricity Efficiency Policy Group, 2003.

81 Yatchew, 2001.

82 Distributors' Electricity Efficiency Policy Group, 2003.

83 Littlechild and Yatchew, 2003.

detailed timetable for generation divestiture. This strategy could potentially involve dividing OPG's generation assets into, for example, five-to-eight separate entities and privatizing one of them every two years beginning in 2006 or earlier. Goulding (2003) argues that OPG should be divided into five generation companies, each holding a mix of peaking and base-load capacity.[84]

Jurisdictions with successful market-oriented electricity industries have undertaken substantial restructuring and privatization. In England and Wales, where electricity restructuring is widely considered to be the most successful in the world, the vertically integrated, state-owned monopoly provider, the Central Electricity Generating Board (CEGB), was de-integrated into a few generation companies and a transmission firm. Two generation companies held the CEGB's non-nuclear power facilities and the government privatized them, beginning in 1991. The government oversaw the formation of two state-owned companies to manage the country's nuclear power plants, privatizing one of them, British Energy. Then, it restructured the distribution network into 12 privatized regional electricity companies (RECs). RECs are permitted to provide generation services as long as their capacity comprises no more than 15 percent of their peak demand.[85] The government initially gave the RECs ownership of the transmission company, but later required them to divest their shares in 1995, enabling a new transmission unit, the National Grid Company, to form. The privatized grid company owns and operates the grid.

In Australia, the state of Victoria pursued a similar strategy. In 1993, the state government separated the State Electricity Commission of Victoria into its generation, distribution and transmission components. The state split the generation component into a number of companies. The government consolidated its 29 distribution companies into five. Victoria allocated its transmission grid to a new state-owned company. It later privatized the companies.

Electricity prices in the United Kingdom and Victoria have fallen following restructuring and privatization, although other factors, such as the cost of fuel and continued price regulation, also influenced prices. In the United Kingdom, the average consumer's bill for electricity decreased by 30 percent in real terms between 1990 and 2001.[86] In Victoria, between 1989 and 1999, average electricity charges fell by 20 percent in real terms.[87]

Generating New Investment

The most critical issue facing Ontario is maintaining adequate generation capacity. Approximately 40 percent of Ontario's existing capacity will shut down or require substantial refurbishment over the next 15 years. The 1140 MW coal-fueled Lakeview plant is scheduled to shut down in 2005. The new government of Ontario

84 Goulding, 2003.

85 Crow, 2001.

86 UK Electricity Association, 2002.

87 Stockdale, 2001.

has pledged to retire all of the province's coal-fired generation plants, providing 7560 MW of generation capacity, by 2007, replacing them with natural-gas fired and renewable generation, including wind and hydro-electric power. These replacement generation facilities are more expensive than coal generation; investors say, for example, that wind power requires a price of approximately 8 cents per kWh to be economically feasible.[88] If the new government is committed to retiring all coal plants, then new generation projects must begin now to meet the 2007 target date. Industry participants estimate that it would cost between $10 billion and $15 billion to replace the coal-fired plants.[89] The Kyoto Accord could place additional pressures on the province to retire coal-fired plants. The new government also has plans to orchestrate a net expansion of the province's supply through renewable generation.

Many commentators say that the current policy environment requires some form of government intervention to acquire sufficient generation supply. However, Jaccard (2002) argues that investors, and not taxpayers, should be exposed to the risks associated with large-scale investments.[90] Indeed, private investors routinely make significant capital investments under conditions of significant uncertainty. However, the current policy climate and OPG's market dominance in Ontario makes private investment in the electricity market unlikely. Ultimately, if it is to attract efficient private-sector investment in a way that benefits electricity users, the provincial government must credibly communicate a commitment to competitive generation markets. Until such a commitment is made, the government will have to induce and directly construct new peak-load generation to ensure supply reliability over the next several years.

Capacity Payments and Capacity-Reserve Requirements

A capacity reserve-requirement system rather than more interventionist approaches, such as requiring a specific proportion of the province's needs to be provided by a specific form of generation technology, as well as subsidizing the technology chosen, may be the preferred instrument for ensuring supply reliability in the province.

Other jurisdictions that have restructured and deregulated markets have used different measures to encourage investment in generation and ensure supply reliability. Measures have ranged from complete reliance on price signals to government construction of reserves. Extreme examples are California and the Australian State of Victoria. As a result of its electricity crisis, California created the California Consumer Power and Conservation Financing Authority with a mandate to ensure that the state continuously has a 15-percent generation reserve capacity.[91] This type of intervention is antithetical to encouraging private-sector investment in the long-run. In contrast, the State of Victoria relies on price signals.

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88 Ontario Wind Power Task Force, 2002.

89 "McGuinty unveils costly hydro plan," *Globe and Mail*, (September 30, 2003), p. A1.

90 Jaccard, 2002.

91 Borenstein, 2002.

England and Wales relied on a mixture of price signals, mandated divestiture and capacity payments. A typical capacity payment involves paying a generator to make capacity available, even if the generator is not required to supply power, with the payment inversely related to the capacity-reserve margin.[92] In 2002, generation capacity in the United Kingdom was estimated to be in excess of maximum demand by 22 percent.[93] Jaccard (2002) recommends that Ontario also adopt a form of capacity-payment system.[94] However, it should be noted that, in England and Wales, there was evidence that some generators abused the system in order to maximize capacity-payment revenue.[95]

Alternatively, the Pennsylvania-New Jersey-Maryland (PJM) system uses a capacity-reserve requirement. The PJM requires "all load-serving entities" — utilities and retailers — to have contracted sufficient capacity to satisfy peak demand and hold a 19-percent reserve, which is reviewed and adjusted periodically.[96] Stoft (2002) argues that while a capacity-reserve requirement has problems, such as the fact that regulators must be able to measure demand elasticity, and define and confirm capacity, it is a direct way to address the issue of supply reliability.[97] Sweeney (2002) 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."[98] A common capacity-reserve requirement is 18 percent over peak demand.[99] A capacity-reserve requirement has the benefit of increasing the use of forward contracts, although not necessarily long-term contracts; however, it will require consumers to pay a premium for the excess capacity.[100] LDC consolidation would make enforcement of a capacity-reserve requirement a more feasible option.

Power Purchase Agreements

Some industry participants argue that local distribution companies or the government, through the OEFC, enter 10-to-20 year power-purchase contracts with generators. As part of its plan to phase-out coal-fired generation by 2007, the new provincial government said it intends to contract with the private sector for new natural-gas fired generation plants. There are numerous forms of long-term contracts that can be arranged, including fixed-price contracts and cost-indexed price contracts.[101] We have already noted the benefits of voluntary, long-term

92 Jaccard, 2002.

93 OFGEM, 2002.

94 Jaccard, 2002.

95 Kwoka, 1997. England and Wales discontinued use of the capacity payment system in 2001; whether this was a prudent measure remains to be seen.

96 Crow, 2001.

97 Stoft, 2002.

98 Sweeney, 2002.

99 Stoft, 2002.

100 Sweeney, 2002.

101 Onofri, 2003.

forward contracting for encouraging new investment. However, while the use of long-term purchase agreements would attract private-sector investment, we are skeptical of the benefits resulting from the province directly entering into, or forcing LDCs to enter into, long-term power contracts because this strategy entails involuntarily shifting market risks from investors to electricity ratepayers and, potentially, taxpayers. Further, having a significant amount of electricity under long-term contracts is not favorable to competitive generation markets.

Some industry participants recommend that the OEFC enter into long-term forward bilateral contracts with electricity suppliers, then re-sell power to LDCs. These contracts could specify a price range — a floor and a ceiling. The LDC would be required to pay the OEFC the spot price within the price range. To avoid excessive price volatility following the re-opening of the retail market, these contracts would be designed to expire sometime after the retail market reopened. This arrangement would overcome the monitoring problems associated with a large number of inexperienced LDCs negotiating contracts with suppliers. However, this method would not necessarily ensure that efficient power purchase contracts — in terms of purchase-price and contract duration — would be negotiated or that efficient price ranges would be identified. Additionally, when the contracts expire, the problem of how LDCs should contract for electricity will re-emerge.[102] To limit the possibility of paying excessive prices, some industry participants recommend that the OEFC enter into relationships exclusively with new generators. Some commentators say that if the OEFC enters into power purchase agreements, it should be made into a regulated public utility overseen by the OEB.

Experience shows that government contracting for power is an extremely risky and expensive proposition. Ontario Hydro entered a number of long-term power purchase agreements (some of the contracts do not expire until 2048) involving billions of dollars with non-utility generators in the late 1980s and early 1990s at what many consider to be above-market prices, although some credit these arrangements for keeping the lights on during the summer of 2002. Following its electricity crisis, Sweeney (2002) estimates that California entered approximately US$40 billion worth of power contracts that are likely to have a value of only US$20 billion.[103] The costs of these contracts will be paid for from higher rates to electricity ratepayers or through higher taxes.

It should be noted that arguments by generators that long-term contracting is necessary to attract private investment are not entirely compelling. In some cases, the claim may be an attempt to capitalize on the province's pressing need for new generation, coupled with the information asymmetries between electricity producers and the government regarding the realities of the industry. For example, Rothwell and Gomez (2003) argue that forward contracts in electricity markets between private producers and consumers typically do not last more than a few

102 Hunt, 2002.

103 Sweeney, 2002.

years and that financiers consider other factors when making lending decisions.[104] 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.[105] However, it must be recalled that capital markets lost confidence in the electricity sector following the California crisis and the collapse of Enron. We should also keep in mind that the MPMA rebate and frozen retail prices reduce the incentives for consumers and LDCs to enter into long-term forward contracts.

Increase Demand Responsiveness

Competitive markets are usually defined as possessing demand and supply responsiveness. It is now widely argued that the best method of overcoming short-term capacity constraints, as well as ensuring long-run efficiency in electricity markets is to increase demand responsiveness.[106] The nature of electricity supply and demand suggests that a slight decrease in demand may mitigate price spikes and preserve system reliability in a period of tight supply. During its electricity crisis, California had to resort to rolling blackouts with a supply shortage of only 300 MW.[107] Real-time pricing may have prevented this from occurring.

During the recent provincial election campaign, the now-elected Liberals pledged to maintain the current retail freeze until 2006. In 2006, the new government plans to implement an administered price system, involving a set of prices for low- and high-demand periods, as well as a set price for a basic amount of consumption and a higher price for consumption over the basic amount. It would also install time-of-use meters in residential households by 2006.

However, as noted, the cost of the price freeze has led the newly elected government to introduce an interim tiered pricing regime. The interim rate structure is to last until the OEB develops a new electricity pricing plan, required to be implemented no later than May 1, 2005. While the interim rate structure is better than the previous frozen rate because it will encourage some conservation and cost less to maintain if whole prices exceed the fixed price, it is far from ideal. Fixed prices, whether determined by the government or the OEB, are inefficient because they do not provide accurate signals regarding actual conditions of supply and demand. Variable prices, reflecting those conditions, rather than a set of administered prices, are necessary for the long-run sustainability of Ontario's electricity system.

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104 Rothwell and Gomez, 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).

105 The authors would like to thank Steven Stoft for this observation.

106 Hunt, 2002.

107 Hunt, 2002.

Ontario's current freeze leaves approximately half of the total volume of electricity consumption not exposed to changes in electricity prices, including some large users, jeopardizing system reliability during periods of high demand and tight supply. Exposing consumers to variable prices reduces overall price volatility, the need for peak-time generation units, transmission capacity, capacity payments, and capacity-reserve requirements. Charging users the true price of electricity should encourage conservation and demand-shifting, as well as increasing the use of products that conserve electricity, creating incentives for manufacturers to develop appliances and equipment that consume less electrical power, eliminating the need for more interventionist methods of promoting conservation.[108] The previous provincial government introduced a public education campaign promoting energy conservation and retail sales tax rebates for a number of eligible energy efficient products, such as dishwashers and solar energy systems for residential use. Etcheverry, Stewart and Hall (2003) argue that Ontario should increase energy efficiency standards for appliances and buildings.[109] The need for such programs is a signal that electricity prices are artificially low.

In Ontario, and most jurisdictions, real-time metering and billing is limited almost exclusively to large electricity consumers like industrial and commercial users. Ontario has 90 industrial consumers, accounting for approximately 15 percent of demand, directly connected to the transmission grid with interval meters that measure and report hourly consumption, enabling the user to be billed at the actual hourly spot price.[110] The IMO estimates that a further 20 percent of total demand comes from industrial consumers not directly connected to the grid, though possessing interval meters.[111] These consumers reduced consumption in response to the rising prices of the summer of 2002 by shifting from peak to off-peak hours, maintaining system reliability and preventing black-outs.[112] A recent study by Reiss and White (2003), examining the California electricity crisis, shows that residential customers also reduce consumption in response to rising prices.[113]

Many commentators say that the best way to achieve substantial demand responsiveness is through retail competition. In a competitive retail market consumers should be able to choose a price package, whether fixed-prices, seasonal prices, or real-time pricing, depending on their preferences.[114] However, the

108 Joskow, 2002.

109 Etcheverry, Stewart and Hall, 2003.

110 IMO, 2002a.

111 Ibid, p. 18.

112 IMO, 2003b. An analysis of 18 large industrial consumers found that they were able to reduce their electricity bill by an average of $8 per MWh from May 2002 to December 2002 by shifting consumption from peak to off-peak hours. Facing a frozen price of $43 per MWh would have increased their demand for electricity by 200-300 MW during some peak-hours of the summer of 2002.

113 Reiss and White, 2003.

114 Cicchetti and Long, 2000.

benefits of retail competition in electricity markets have been elusive, partially because of retail price caps. Competitive retail markets have not resulted in a greater use of real-time pricing. Joskow (2000) argues that in the absence of real-time pricing and other value-added services — such as a consolidated electric, gas, telephone and cable bill, or offering green power, such as solar and wind power — retail competition offers few benefits to residential and other small customers.[115] Some industry participants say that the spot-price pass-through, which can be implemented without competitive non-utility retailers, is the most efficient pricing regime for customers.

While almost 40 percent of customers in Britain have switched to a non-incumbent retailer, in many jurisdictions customers have not changed over from the incumbent utilities in large numbers, partly because of continued retail rate regulation. It is important to note that England and Wales gradually implemented retail competition — completed in 1999 — and did not fully deregulate retail prices until 2002.[116]

Transmission

The province must develop a strategy for the expansion and maintenance of the transmission grid. In March 2003, the IMO stated that some regions of Ontario, including the GTA, require transmission network reinforcement within the next few years to ensure future supply reliability.[117] Additionally, the congestion of the transmission system's inter-ties during peak-demand periods indicates a need to increase the province's electricity import capacity in order to expand and diversify sources of supply. Increased inter-tie capacity will increase system reliability because the province will have access to additional generation resources in the event of an unexpected domestic outage and extreme weather.

However, politically, the expansion of inter-tie capacity cannot be viewed as a perfect substitute for new domestic generation. For example, some citizens and political groups may oppose increasing Ontario's reliance on imported power, or limit the ability of domestic generators to export power. Alternatively, domestic generators may oppose expanding inter-tie capacity if new imports significantly reduce prices. The political opposition to transmission integration appears to have increased following the blackout of August 2003; some jurisdictions, including Ontario, have indicated a desire to become more self-sufficient in generation capacity, regardless of efficiency consequences.

Transmission planning and expansion in a deregulated and privatized market remains an unsettled issue. A conflict between transmission and generation capacity expansion arises as a result of deintegration. Watts (2001) argues: "[w]ith regulated generation, grid expansion decisions can be made in the context of

115 Joskow, 2000; Hunt, 2002; Stoft, 2002.

116 In England and Wales, in 1990, users with a demand of 1 MW or more had the option of buying electricity on the competitive market. In 1994, retail competition was made available to customers with a maximum demand of 100 kW or more. In 1998, competition began to be introduced to customers using under 100 kW. All customers were able to choose their supplier by May 1999. In April 2002, retail price controls were removed.

117 IMO, 2003c.

generation plans. It is not clear, however, how these decisions can be 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."[118] According to Hunt (2002), a "transparent and stable 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 planning is used.[119]

Jurisdictions have adopted different mechanisms for managing transmission network planning. In PJM, the region's independent system operator works with industry stakeholders to develop an area plan for generation and transmission expansion. In England and Wales, the privatized grid company is responsible for transmission planning.

Market Integration

Ontario should harmonize its market rules with those of surrounding jurisdictions. Greater integration will promote the efficient use and expansion of inter-ties. It may be worthwhile to move to hour-ahead and day-ahead markets used in neighboring jurisdictions, rather than the current five-minute-ahead market that Ontario currently utilizes, which would be retained as a balancing mechanism. A day-ahead market would increase generation efficiency within Ontario. The province's current five-minute ahead market creates inefficient generation decisions on bidding plants and prices because some plants, especially older fossil-fuel generation units, require more time to ramp up and down. The IMO is considering establishing a day-ahead market similar to that used by New York and New England.[120]

Ontario should also strengthen information flows with neighboring jurisdictions about generation and transmission capacity, demand and prices. Commenting on generation, Sweeney (2002) states that "good information about historical and current conditions and reasonable projections of future conditions throughout the region can help to avoid boom and bust cycles in the electricity markets."[121]

Electricity Rates

It should be recalled that not only is the retail price of electricity frozen, but all electricity charges in Ontario, such as transmission and distribution, are capped or frozen. This cannot be sustained indefinitely. The caps and freezes must be lifted to ensure that the funding necessary to maintain the power network is available. To its credit, the new provincial government has indicated that it will remove the current freeze on distribution and transmission rates.

118 Watts, 2001.

119 Hunt, 2002.

120 IMO, 2003.

121 Sweeney, 2002.

Locational Pricing

Ontario consumers currently pay a postage-stamp retail price and transmission charge. Postage-stamp pricing is a flat rate paid by all consumers, regardless of location. A postage-stamp transmission charge is designed to pay for the fixed costs associated with maintaining the transmission grid. However, exclusively using this form of pricing is inefficient because it does not charge consumers the true cost of transmitting electricity to their location on the grid; there is congestion among nodes, creating locational differences in the costs of delivering electricity. As well, postage-stamp pricing does not provide locational signals for transmission and generation investment. These problems can be overcome by using nodal or zonal – locational — pricing.

Zonal and nodal pricing involves setting multiple spot prices that reflect the relative amount of transmission capacity at a particular delivery point, or region, of the grid.[122] These prices "are continuously adjusted over time and are set for delivered energy, including both the price of energy and the price of transmission."[123] The difference between locational prices indicates the value of transmission.[124] This type of pricing creates signals for conservation by consumers, as well as efficient grid and generation capacity expansion. The Ontario Market Design Committee recommended that some form of zonal or nodal pricing be progressively implemented following restructuring. Nodal pricing, which is used by PJM, is considered the most efficient form of locational pricing. PJM uses nodal pricing.

Performance-Based Regulation

Following the price freeze, written approval from the Ministry of Energy is required to alter transmission and distribution rates. This may politicize the rate-making process and compromise the ability of utilities to finance investments in the distribution and transmission network. The provincial government should commit to returning to prudently designed performance-based regulation (PBR) ratemaking for transmission and distribution rates by an effective and independent OEB.

Prior to the current freeze, the OEB was implementing a PBR regime for setting distribution rates. A typical form of PBR sets an initial rate for market opening with the rate varying over time according to a pre-set formula that increases rates as a result of industry-specific input price inflation of labor, materials and capital costs, and decreases rates according to productivity gains and other factors. There are other forms of PBR.[125] Performance-based regulation prevents the charging of monopoly prices, while the regulatory lag between rate changes maintains incentives to increase profits through cost reductions.[126] However, PBR may

122 International Energy Agency, 2001.

123 Ibid.

124 Rothwell and Gomez, 2003.

125 Ibid.

126 Joskow, 1997.

127 Ibid; Rothwell and Gomez, 2003.

provide incentives to reduce service quality in order to increase profits.[127] England, Wales, and the State of Victoria use forms of PBR for setting transmission and distribution rates. Prior to full price deregulation, England and Wales, as well as Victoria applied PBR to retail electricity rates.

Adams (2000) argues that the OEB's formula for distribution ratemaking is flawed.[128] Leading up to market opening, the OEB allowed LDCs to collect a rate of return based on historic capital that had already been paid for by ratepayers, resulting in significant distribution rate increases for some customers prior to market opening.[129] Some industry participants argue that LDCs should be permitted to earn a return only on new investment in the system.

Protection of Low-Income Consumers

With low-income users, the government may wish to consider mandating a life-line consumption amount of approximately 300 kWh per month at, for example, 4.3 cents per kWh, to ensure that all consumers receive basic service. All consumption in excess of the life-line amount should be charged at the prevailing market price. However, some industry participants say that a targeted subsidy would be difficult to implement because of problems with identifying who qualifies. Down et al. (2003) suggest granting a tax credit to low-income consumers.[130] Another alternative is to charge all residential consumers a price of, for example, 4.3 cents per kWh for the first, say, 300 kWh per month of consumption, and the market price for additional consumption. Both systems preserve price incentives to conserve at the margin, are simple to administer and are significantly less expensive than the present retail price freeze. The new government's interim pricing plan, through its low first tier price, is sensitive to the needs of low income users.

Conclusions

Ultimately, a lack of political will to pass higher and economically justified electricity prices on to consumers and restructure the generation market to attract private investment is responsible for the current disarray of the province's electricity sector. Rather than reducing the province's electricity-sector debt, lowering prices and encouraging private sector investment in generation, Ontario's restructuring experiment resulted in new electricity-sector debt and higher prices, while discouraging private-sector investment in generation. It may be plausible to argue that, because of the government's lack of commitment to market reform, Ontario would currently be better off, in terms of electricity supply, if restructuring had not been pursued. However, even if Ontario Hydro was not restructured, the province would still face the current problems of a lack of demand responsiveness and the substantial financial commitments necessary to sustain a stable electricity network.

128 Adams, 2000.

129 Ibid.

130 Down et al., 2003.

Continuing to regulate retail electricity prices is not the solution to Ontario's electricity problems. Whether the electricity sector is privately or publicly owned, consumers and producers of electricity need to face prices that reflect actual conditions of supply and demand. Such an environment is necessary for the long-run stability and fiscal sustainability of Ontario's electricity system. Exposing consumers to prices that reflect market conditions will create the appropriate demand-side incentives to conserve and use products that conserve electricity, and the supply-side pressures necessary for efficient generation and transmission investment. The cumulative effect of this setting will be reduced price volatility and a lesser need for excess generation and transmission capacity. All electricity users in Ontario should, at the very least, have the option of choosing market-based pricing.

Prior work regarding government intervention in response to economic shocks has noted that "policies that do not address the root problem, but rather deal only with the consequences of a shock on an ad hoc basis create future costs and can exacerbate the impact of a particular shock."[131] As this *Commentary* has attempted to point out, much of Ontario electricity policy, despite the work being carried out through the IMO's Market Evolution Program, is being directed at the consequences of the electricity price shock, creating substantial, and potentially debilitating, hidden future costs for Ontario taxpayers and electricity ratepayers, as well as exacerbating the supply-demand imbalance.

Proposed generation and transmission projects will quickly exceed several billions of dollars, requiring the province to make tough choices about financing electricity infrastructure, such as reducing expenditures in other areas, raising taxes or increasing the debt-retirement charge, in the absence of private-sector finance. Policymakers would do well to recognize that the current model of public ownership is flawed. The province's abysmal record at completing major power projects on time and within budget over the past few decades — Darlington and Pickering, for example — is evidence of a lack of accountability mechanisms.

There is much work to be done in Ontario towards creating a more stable and efficient electricity market that is congruent with political realities. As Costello (2003) notes with respect to the United States, "in a democracy where people have varying views it has become obvious that a political will in favor of a market-oriented electricity industry does not exist at this time."[132] The observation is an apt description of Ontario. Recommendations in this paper that should be carefully considered by any government are:

- Offer all consumers the option of market-based pricing, or increasing demand responsiveness through real-time metering and pricing for electricity users not covered by regulated retail prices;
- Split OPG into multiple companies;
- Encourage distribution-sector consolidation;

131 Iacobucci, Trebilcock, and Haider, 2001.

132 Costello, 2003.

- Legislate a capacity-reserve requirement;
- Develop a framework for transmission expansion and upgrading;
- Harmonize market rules and increase information flows with neighboring jurisdictions and,
- Adopt nodal or zonal pricing and a renewed commitment to effective performance-based regulation for transmission and distribution rate-setting.

The current government has the opportunity to implement these reforms; the question is, does it have the political will?

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