The Future of Nuclear Power
in
A Restructured Electricity Market

September 3, 1999

DRAFT
Comments welcome
Please do not quote

Professor Donald N. Dewees
Department of Economics
Faculty of Law
University of Toronto

Prepared for the Conference on the Future of Nuclear Energy in Canada, Carleton Research Unit on Innovation, Science and Environment, Ottawa, September 30, October 1, 1999. I want to thank Jeff Carr for extensive research assistance.

I. Introduction

For an economist, the future of nuclear power in a restructured electricity market depends in the first place on the economics of nuclear generation in such a market. If we regulate the environmental effects of nuclear and non-nuclear forms of generation so that we have achieved the right balance between cost and environmental protection, then the decision about the operation, refurbishment, or construction of nuclear units or any other unit should depend primarily on the cost of the power from that operation or construction in comparison with the cost of other competing sources of power. This is a big Aif@ of course, and I would not want to argue that the government has always found the right balance in the past. Those who believe that the environmental costs of electricity generation have not been fully incorporated into the costs of generation by existing regulations can argue that the under-regulated form of generation should be subjected to some form of penalty, perhaps an Aenvironmental adder@ to represent social costs not captured in regulation. In this way, even those who are not satisfied with existing regulations can still participate in an economic evaluation of alternative modes of generation.

What does electricity restructuring have to do with the future of nuclear power? In principle, restructuring means taking power away from monopolists and regulators where feasible and giving it to the competitive market. This means eliminating the existing monopoly on generation and allowing competitors to invest in generation subject only to market forces and transmission capacity. The 1997 government White Paper (Ontario, 1997, p. 13) calls for making generation investment based on business-like basis. This in turn means that the future of nuclear power should depend not on government policy toward nuclear power nor on the relative power of the nuclear division within the bureaucracy of Ontario Power Generation Incorporated, the successor to Ontario Hydro. Instead the future should depend on how investors and bankers assess the projected cost and revenue streams with their attendant risks from proposed nuclear projects. Restructuring also means that the transmission system and distributors must provide open access so that power can flow from competitive generators to end users.

In a regulated market, the monopoly utility invests in generation and the regulator allows it to earn a reasonable rate of return on the assets. If new capacity is more expensive than existing capacity the regulator allows rates to rise to cover the cost, unless the regulator believes that some of the cost was not reasonable and should be disallowed. (Joskow, 1997, p. 125.) If new capacity is less expensive, its commissioning should reduce electricity rates. In a restructured market, when new capacity comes on line it bids into the market or sells under private contracts for whatever price it can get. So an evaluation of the economics of nuclear power in a restructured market is quite different from that evaluation in a regulated market.

How has restructuring proceeded in Ontario? In late 1995, the Ontario government appointed the Advisory Committee on Competition in Ontario=s Electricity System, chaired by the Honourable Donald MacDonald and more conveniently know as the MacDonald Committee Ato study and assess options for phasing in competition in Ontario=s electricity system.@ That committee reported in 1996, recommending the establishment of wholesale electricity competition with retail competition to follow as soon as possible. (ACCOES, 1996 p. iii.) In November, 1997, the government issued a White Paper, ADirection for Change@ announcing that it had developed a plan to introduce full competition into Ontario=s electrical system in the year 2000. (Ontario, 1997.) The government appointed the Market Design Committee at the start of 1998 to develop recommendations for the design of this market and received four reports roughly at the end of every quarter in 1998. When the MDC completed its work and made its final recommendations in January, 1999, it passed the responsibility for further refining and implementing those recommendations to the government, the Ontario Energy Board and to the Independent Market Operator which was to administer the market rules. This paper is based on the status of restructuring in Ontario as of the summer of 1999, with a focus on the recommendations of the MDC of which I was Vice-Chair.

The elements of a restructured electricity market in Ontario, and in many other jurisdictions, are several:[1]

$ An independent system or market operator (ISO or IMO) dispatches generation in merit order and establishes a spot price ensuring supply;

$ Generators bid their units and invest according to private profit calculations;

---

[1] For a general discussion of restructuring, see Hunt and Shuttleworth (1996), OECD (1997), Daniels (1996), Joskow (1997), Barker Tenenbaum and Wolf (1997), Helm and Jenkinson (1997). This paper discusses what Joskow terms the Acustomer choice@ or Aretail wheeling@ model which appears to be the dominant model in North America. The alternative is a more modest Aportfolio manager@ model in which the distributor retains a monopoly in its service area but purchases power in a competitive market.

$ The transmission owners/operators keep the transmission wires operational, charge a regulated tariff and invest according to private profit calculations or orders from the regulator;

$ Distributors keep the distribution wires operational, charge regulated rates, and provide a standard price to customers who have not chosen a competitive retailer;

$ The environmental agency regulates environmental aspects of the electricity system including air emissions from generators;

$ Parties can enter into contracts for the purchase or sale of electricity at the wholesale and retail levels.

This paper will review the operation of the wholesale market which determines who generates power and the spot price. It will look at the rules for investment in generation capacity, including investment in renovation or life extension of existing plant. It will look at retail competition and SSS to see how end users have access to generation of any type. It will examine environmental regulations which may significantly affect the price of price-setting thermal plants. It will consider evidence regarding the future price of electricity which is crucial to any generation investment decision. Finally, it will assemble these elements to assess the principal factors influencing the future of nuclear power in Ontario.

II. The Wholesale Market

In a regulated monopoly electricity regime, the regulator approves rates for electricity consumers that are designed to cover reasonable utility costs and a reasonable rate of return on assets. Typically, rates are set annually. In Ontario, the Ontario Energy Board has had the authority to review Ontario Hydro=s rate proposals and to hold hearings on them, but the rates have ultimately been set by Ontario Hydro, not by the OEB. This procedure, quite unlike that in most US states, presumably reflects Ontario Hydro=s status as a crown corporation which should make it more attentive to the public interest than a investor-owned utility could be expected to be. Ontario Hydro=s mandate is to produce Apower at cost@ so the result should be similar to that in a US jurisdiction: rates cover all costs including capital costs.

In a restructured electricity market, wholesale electricity prices are set by competition not by regulation. In the Ontario market, the Independent Market Operator (IMO) will accept bids by generators to supply electricity and ancillary services for each hour of the day, on a day-ahead basis. The IMO will accept bids in merit order, starting with the lowest bids and moving up to higher priced bids until the anticipated demand is satisfied. Wholesale customers can submit demand bids which are offers to reduce their demand if the price reaches specified levels. Once the IMO has determined the market-clearing bids, it directs the generators whose bids are accepted to run as bid, and it announces the market-clearing price. All generators that are so dispatched receive the market-clearing price or Aspot@ price for the amount that they actually generate. Wholesale customers pay this spot price plus any Auplift@ specified in the market rules.

Wholesale market participants can operate in the pool as described above or they can operate on the basis of Aphysical bilateral@ contracts. Physical bilateral contracts are agreements between individual buyers and sellers of electricity regarding both quantity and price which are netted out of the IMO settlement process. Parties to a physical bilateral contract may notify the IMO of the amount of energy that they have scheduled between them and where it is to be injected and withdrawn from the transmission grid as well as the price at which they would vary these amounts. The IMO dispatches the generation as scheduled and subtracts such scheduled quantities before doing the settlement calculations for payments to generators and charges to loads, so that the financial transactions for these amounts bypass the IMO, except that deviations from scheduled quantities are settled at the spot price and the IMO may levy any uplift charges applicable to all energy.

The Ontario electricity market is a hybrid market with a voluntary pool and with physical bilateral scheduling. Of course, pool participants can enter into financial contracts with each other that will be settled as differences from the spot price. Thus wholesale participants can buy and sell at the spot price or they can do so at any other price that they choose, either settling through the IMO and with contracts for differences, or settling outside the IMO except for deviations. The IMO is responsible for accepting bids and for dispatching generation sufficient to satisfy all loads at all times, generating a spot market price in the process.

In such a market, if generation is competitive, the profit-maximizing strategy for any generator is to bid its short-run marginal costs, just as the profit-maximizing strategy for any competitive firm in general is to set output so that price equals marginal cost. The result is a spot market price that reflects in every hour of every day the short run marginal cost of the most expensive plant that must be dispatched to satisfy the load. This price will vary hourly, rising as load increases or as available generation capacity falls. The price should be higher during the day on week days than at night or on weekends because of business demand; it should be higher in winter when heating demand peaks and in summer when air conditioning demand peaks; it should be lower in the spring and fall when demand is lower and it should be lower in the spring when the flow of water available for hydroelectric generation is greatest.

Nuclear plants have high capital costs and low operating costs and are not well adapted to rapid changes in output. The preferred mode of operation is to bring a nuclear unit up to its capability and to run at that output continuously. Nuclear plants might bid a price of zero to ensure that they were dispatched and bid a quantity equal to their capability.

This discussion of the wholesale price has dealt with a single price for the entire province of Ontario. However the transmission grid can be congested at times of peak usage, and congestion causes the value of generation to vary with location. If a transmission constraint exists between zone A and zone B because of the flow of electricity from A to B, low-cost generators in A may be constrained off and more expensive generators in B may be dispatched. In this situation, the value of electricity in B is greater than in A. In consequence, the MDC recommended that 19 months after the market opens a system of locational pricing should be established so that the price of electricity would reflect transmission constraints, thus providing efficient incentives to locate new generation and new loads. (MDC, 1998b, RM 3-6.) This locational pricing will likely cause only small differences in the annual average price in various locations, but even these differences may have some effect on generation investment decisions, including investments in nuclear power. The general effect of locational pricing over the long run should be to encourage the location of new generation in areas where there is insufficient generation capacity.

The price to the consumer must include a transmission charge for use of the transmission network. Setting a transmission charge efficiently is difficult because the marginal cost of sending electricity over an existing transmission network is approximately zero unless the network is seriously congested, so marginal cost pricing cannot recover the sunk cost of the existing network. The solution recommended for Ontario, at least for the first few years, is average cost pricing, in which the OEB would approve a transmission tariff that covers the fixed and operating costs of the transmission operators. The tariff would be uniform for all customers in the province. Moreover, to avoid uneconomic bypass of the transmission system, if new generation is built to serve local customers (Aembedded generation@), those customers would pay for their electricity consumption on a Agross load@ basis, paying as if the load served by the new generation used the transmission system. (MDC, 1998c, RMs 2-1, 2-2.) These recommendations remove the incentive to build imbedded generation that would have marginal costs higher than the marginal cost of the existing generators (the spot price) but lower than the spot price plus the transmission charge. This means that existing generation plants, including nuclear plants, compete on a level playing field with new generation plants, whether they are located on the grid or within the service area of a distribution company.

III. Generation Investment

In a monopoly electricity market the utility is responsible for ensuring adequate capacity within its own plant after considering the available excess capacity in adjoining utilities. Regulated utilities tend to install substantial capacity reserves because of the adverse publicity and the real costs imposed if capacity should prove to be inadequate, requiring brownouts or blackouts. In Canada, where most electric utilities are owned by provincial governments there may have been some temptation to encourage new generation investment to Acreate jobs,@ with the cost appearing in electricity prices, not taxes. Investments in new capacity are paid for by customers as their costs are rolled into the cost base when the capacity comes on line, subject to review of the reasonableness of the investment by the regulatory agency.

In Ontario, with the ultimate responsibility for setting rates residing with Ontario Hydro, the costs of new investments were simply rolled into the overall cost of electricity. As a result, when the Darlington plant was completed and brought into service between 1990 and 1993, bulk power rates increased by a cumulative total of about 28 percent over a four year period[2] although the final cost of the plant was much greater than the original cost estimate, and even though slow economic growth meant that much of the capacity was surplus when it became available.

The 1997 White Paper explicitly called for investment decisions to be made in a more business-like fashion:

> History has shown that competitive businesses invest more carefully than monopoly businesses. They manage costs and risks more carefully. They choose their priorities rationally and thoughtfully to yield the highest returns. This is the kind of investment behaviour that should predominate in the future electricity industry in Ontario. They serve their customers better and they maintain competitive prices because of the threat of competition.
>
> An important objective of reform is to ensure that new supply decisions - including replacement supply decisions made over the 1998-2000 period - are made on businesslike grounds, and subject to normal market tests. A competitive market will impose more discipline on investment decisions and will help the industry avoid both the overbuilding and asset impairment that occurred in the past. (Ontario, 1997, p. 13.)

The MDC=s market design embraces this philosophy, leaving generation investment decisions to the private market. The IMO will have the responsibility to perform long-term market outlook studies from time to time which will be based on the best information available to the IMO and may provide input to individual generation investment decisions. But those decisions will be in the hands of private investors. The MDC was reasonably confident that investment decisions made purely on the basis of current and forecast electricity prices would yield adequate capacity investments, despite the long lead times associated with traditional utility plants. Out of an abundance of caution, however, and in light of the Alberta experience with

[2] Rate increases taken from Ontario Hydro allocation of cost increases to the Darlington plant in Exhibits filed at Ontario Energy Board rate hearings: 8.9%, Ex 1.1.14, April 10, 1989; 5.8%, Ex 1.1.13, April 2, 1990; 4.2%, Ex 1.1.12, April 2, 1991; 6.4%, Ex 1.1.11, April 2, 1992.

short-term high prices during 1998, the MDC provided that the IMO could, if it believed that investment was inadequate, initiate a Acapacity reserve market@ that would essentially pay a bonus to capacity that was ready to run even if it was not called on. (MDC, 1999, p. 1-8.) The normal investment incentive arising from revenue from generation may therefore be augmented by revenue from the capacity reserve market.

With or without the initiation of a capacity reserve market, the risks of both profit and loss associated with the investments will be borne by the investors. A new plant could be built on a merchant basis, planning to bid into the spot market and take whatever price emerges. Alternatively, if investors can persuade individual large consumers or groups of consumers to commit to long-term power purchase contracts at specified prices, the investors can reduce their risks by sharing them with the consumers that choose to enter into such contracts. Approximately one quarter of the Ontario demand is taken by approximately 255 large industrial customers whose peak demands exceed five megawatts, and this pool of customers, who spend over a million dollars per year on electricity, are potential clients for new generators to market their power if they wish to do so on a contract basis. (See Table 1.) Almost half of the Ontario demand is represented by non-residential customers smaller than five megawatts, some of whom will be sufficiently sophisticated to enter into purchase contracts if they are economically attractive. Others in this group will be members of groups such as retail franchises, for which the parent company could be a sophisticated shopper and enter into a purchase contract on behalf of dozens or hundreds of small Ontario outlets that it represents. Retailers can aggregate individual small and medium consumers or groups of consumers and enter into contracts on their behalf. Thus even if most small customers resist retailers and marketers, far more than one-quarter and perhaps one-half or more of the Ontario demand could be signed up for power purchase by new generators if they can offer attractive prices

Any decision to invest in new nuclear facilities will therefore be made by private investors based on their own forecasts of supply and demand, costs and prices. Investments in the renovation, upgrading or life extension of existing nuclear plants will face a similar test. Presumably the investor will forecast the cost of the investment, the operating cost of the plant if the investment is made, the price at which the power may be sold, and the net profit or loss likely to arise from the investment. The investor can make its decision accordingly.

The lead time from the decision to build a new generation plant and the date when the plant first comes on line is an important factor in investor decisions because uncertainty about the demand for output increases with the lead time. By the 1980's, the time between the decision to construct a new nuclear plant and the time when that plant went on line had stretched to well over a decade. The complexity of a nuclear plant gives rise to a construction period longer than that for a traditional coal plant, perhaps 10 years instead of 4-5 years. (Applied Decision Analysis, 1983, pp. S-2, 3-4; Ontario Hydro, 1990, p. 10.) In addition, the high level of public concern regarding the environmental risks of nuclear power can cause time-consuming environmental assessments and delays in other approvals for those plants. In contrast, combined cycle gas turbine (CCGT) plants give rise to minimal environmental concerns and the central components are manufactured to standard specifications so they can be constructed far more quickly than a traditional thermal plant, perhaps two to four years. (Cohn, 1997, p. 249.) The long lead times for nuclear plants mean that they face considerably more uncertainty than coal plants while CCGT plants face considerably less. Worse yet, the uncertainty may be asymmetrical. If forecast prices move downward after the nuclear plant project has started, the nuclear plant must face lower prices unless other new investments with shorter lead times are postponed. If forecast prices move upward, competitors can initiate new generation projects with shorter lead times and thereby prevent the nuclear plant from reaping the rewards of high prices. The increased uncertainty associated with nuclear plants will be translated into higher financing costs to cover these risks. This is not an artificial barrier to nuclear technology but an inherent aspect of it.

What has been the investment experience in other jurisdictions following restructuring? In the UK, the regional electricity companies (RECs) built a number of CCGT plants which were paid for by their customers because of the RECs’ local monopoly and the regulator’s willingness to allow the costs to be passed through although these plants have turned out to be relatively high cost. (Helm and Jenkinson, 1997, pp. 3, 11.) In New Zealand competition has led to the construction of new capacity and to cost reductions at existing plants leading to price reductions of upwards of 20 percent between 1992 and 1999. In Victoria, Australia the generator was split into five separate generators resulting in cost and price reductions. In Argentina competition has given rise to substantial new investment in generation, even to an extent that appears uneconomic to some. Alberta has been criticized for the price spikes in the summer of 1998 and 1999, but in fact some new capacity is currently under construction.

During 1997, 1998 and 1999 prices in Alberta have reached hundreds of dollars per MWh for a few hours at a time, at times reaching $999, a limit imposed only by the absence of further digits in the computer program. Such price spikes compared to an average Alberta price of $20 to $30 per MWh have lead some to declare that the market was incapable of generating adequate investment in new generation. One explanation for the price spikes is the government’s failure to complete all aspects of the market arrangements, including completing the auction of 6,000 MW of bidding rights that will go on sale in 2000, which created uncertainty that led investors to postpone new capacity. Another explanation is that it is normal that as capacity becomes tight average prices will rise and peak prices will be very high, while after new capacity comes on line the price spikes will moderate and average prices will decline.

How will prices vary over time in competitive electricity markets? Assume that the size of new capacity will not be insignificant compared to the system demand. Assume that when competition begins there is excess capacity so that prices are below long run average costs. Hourly prices will vary with a daily pattern, a weekly pattern, a seasonal pattern and a random component. As time passes and demand grows, the excess capacity will be used up and the annual average prices will rise. At peak periods there may be price spikes, even if only for a few hours, but their effect on average prices will be modest because of their short duration. These average and peak prices will rise until investors believe that their project will be profitable, at which time it will be built. When the new capacity comes on line, average prices will decline, the peaks will become small and rare, and the process will begin again.

IV. Retail Competition

While the wholesale market is the centre of the restructured electricity market, further steps are needed to ensure that all customers benefit from wholesale competition. If the owner of the distribution lines feeding end users has a monopoly on distributing electricity, the benefits can be captured by the distributor and never reach the customer. Restructuring therefore usually involves at least the provision of retail access, or retail competition, so that any customer may choose an electricity supplier other than the distributor.

Typically the distributor is responsible for providing electricity to customers who do not choose a retailer, a service referred to by the MDC as Adefault supply@ and by the Ontario Energy Board as AStandard Supply Service@ or SSS. Customers may receive electricity priced according to the SSS or they may enter into a contract with a retailer under any other terms and conditions allowed by law. While thinking about retail access and the competitive supply of retail electricity, it is important to remember that the Independent Electricity Market Operator (IMO) will accept bids from generators and will dispatch generation sufficient to meet required loads at all times. Electricity will flow according to the laws of physics from generators through the transmission and distribution systems to loads throughout the province. The purpose of retail competition is not to ensure the supply of electricity to a customer; that is the responsibility of the IMO, transmission owners and distributors. Retail competition is about the price and other terms and conditions of the contract under which customers pay for the electricity they consume.

In Ontario, the MDC recommended that default supply be a Asmoothed spot price,@ so that all retail customers who do not choose a retailer will pay the spot price averaged over some period less than a year. (MDC, 1998b, RM 4-3.) The OEB draft SSS Code (OEB, 1999) provides that the smoothing period will be one billing period. This means that the distributor does not have to arrange for electricity purchase at all. The electricity flows from the grid through the distribution lines to customers, the distributor pays to the IMO the wholesale spot price for the electricity that flows from the grid to its lines and customers pay the same price plus a distribution charge.

The implication of this arrangement for investors in generation projects is that the distribution utilities are not in a position to enter into contracts to purchase power at fixed prices. The distributor=s SSS customers can be supplied at the spot price if the generator bids into the spot market. But if the generator wants to supply end users at a fixed price, the generator will have to enter into contracts with individual customers or with retailers who have signed up individual customers.

Some have argued that this spot price pass-through will discourage new generation precisely because generators cannot contract with distributors to supply the default customers. This argument fails to recognize that fully 25 percent of demand is represented by large sophisticated customers who could be purchasers of the output of new generation if the price is attractive while perhaps another quarter of the market consists of somewhat smaller but still relatively large customers or customers who can easily be aggregated. Moreover if the price is attractive a retailer could purchase the fixed price power and sign up smaller retail customers. One powerful argument in favour of the spot price pass-through is that it supports the principle that new generation must pass a market test; either it will be sold for the spot price or it must be sold to willing and knowledgeable buyers, not forced on passive SSS customers many of whom are not sophisticated enough to leave SSS if the price is high.

V. Environmental Regulation

Environmental and safety regulations have had a considerable effect on the cost of nuclear power. Environmental regulations can also have a significant effect on the cost of competing power, principally power from fossil fuel plants. Since 1994 Ontario Hydro has been limited to the emission of 175,000 tonnes of sulphur dioxide per year and the sum of sulphur dioxide and nitrogen oxide emissions have been limited to 215,000 tonnes per year.[3] It has entered into a voluntary agreement with the government to limit nitrogen oxide emissions to 38,000 tonnes per year by the year 2000; to stabilize its emissions of carbon dioxide at 1990 levels by the year 2000; and to reduce them by 10 percent by the year 2010. These agreements apply only to Ontario Hydro and not to any other generator in the province. The MDC (1998b, RM 5-1) urged the government to ensure that air emissions were regulated at least as strictly for the restructured market as they have been for Ontario Hydro, but to date it is not clear what limits the government will impose.

In Ontario, as in many jurisdictions, the price-setting power plants are usually thermal plants, as the nuclear plants run continuously (or not at all), so the cost impacts of environmental regulations will affect the price that nuclear power must compete with in the restructured market. What influence might future environmental regulations and other developments have on the price of this thermal power?

Economic theory calls for environmental regulations to be set so that the marginal cost of pollution control is equal to the marginal benefit of pollution control, that is, the marginal reduction in harm. Dewees (1996, p. 305, 306) reviews some estimates of the magnitude of the harm that may be caused by these pollutants. Ottinger (1991, 111) concludes that a traditional coal-fired plant may cause harm valued at almost $60 US per MWh generated, while a study by Ontario Hydro (1993, p. 81) found a total value of environmental harm caused by air pollution from its coal-fired plants close to $4 CDN per MWh generated. I believe that the true value in Ontario is closer to the latter value, and unlikely to exceed $10 per MWh. Dewees (1990, p. 307)

[3] Regulation 335, Ontario Hydro, RRO 1990.

concluded that the environmental risks of nuclear operation in contrast were likely small, although the risks of major accidents are subject to considerable uncertainty and the costs of decommissioning nuclear reactors may not be small.

Ideally, one would like to know the change in the marginal cost of generation from each existing OPG thermal plant that would result from varying levels of control of each pollutant, as well as the anticipated utilization of those plants, as well as the same information for new generation units that might be constructed in the foreseeable future. I have not found such data. However order-of-magnitude approximations can be found by using published data on the average control cost per tonne for controlling these pollutants and the emission factors for the existing thermal plants. Table 2 shows the weighted average emission factors for SO2, NOX and CO2 for existing OPG thermal plants. In the case of SO2, Smith, Platt and Ellerman (1998, 13) estimate that the long run average cost of SO2 control in the United States under Phase II of the Clean Air Act Title IV program may be about $200 US per ton, equal to about $330 CDN/tonne, which could raise the marginal cost of electricity by $1.23/MWh. In the case of NOX, a 1990 study for the NOX-VOC plan estimated that NOX control could cost from $4145 to $6425 (1989 CDN) per tonne of NOX reduced (Nichols and Harrison, 1990, p. 44). However technology has advanced and costs have declined since that time, and a mid-1990's US report found NOX control costs of $700 US per ton increasing electricity costs by $3 US per MWh, equal to $4.50 CDN/MWh. (OTAG, 1996, p. 6.) We have used these data although Krupnick and McConnell (1999) found higher marginal NOX control costs in the US Northeast. In the case of CO2, there is no technology for abatement, only the possibility of substituting more expensive fuels such as gas instead of coal, which reduces emissions of SO2 and heavy metals as well. To estimate the CO2 reduction effect alone, we calculate the effect of a tax equal to $10 per tonne of CO2 emitted (equal to $37 per tonne of carbon). Such a carbon tax would raise the marginal cost of generating electricity from coal by $9.74/MWh. More generally, with Ontario Power Generation's coal plants emitting almost one tonne of CO2 per MWh of power generated, each dollar of tax on CO2 raises the cost of generation from coal by almost $1/MWh.

These cost data are all point estimates of the cost of achieving a given degree of pollution control. In general the cost of pollution control is low at low levels of control and increases at an increasing rate as the extent of control climbs, that is, as the emission rate is reduced. While estimates of the shape of a control cost function have been made for various pollutants in other situations, I have not found complete cost functions, reduced to cost per MWh, that would be applicable to Ontario Power Generation's thermal plants. We can be certain, however, that for both SO2 and NOX the cost of control will increase more than in proportion to the degree of control. At some point, it will be less costly to convert from coal-fired plants to CCGT plants, a strategy recommended by the Ontario Clean Air Coalition. Once such conversion begins, the cost of further control will probably rise only modestly, in $/MWh, to pay for increased gas transmission capacity until all coal plants have been replaced by gas. In the case of CO2, the only control is to substitute gas for coal, to move to renewable energy including hydroelectric, wind and solar sources, or to use nuclear power.

The most important uncertainty here is the extent and therefore the cost of controlling CO2 emissions. Canada has agreed, through the Kyoto Protocol, to reduce its greenhouse gas emissions to 6% below 1990 levels by 2008-2012 which will require reductions of at least 25% below the business-as-usual scenario for 2008-2012. Burtraw and Toman (1998, p. 23) report that to stabilise US emissions at 1990 levels might involve average costs of $50 US/ton and marginal costs of $100 US/ton of carbon. But a ton of carbon makes 3.67 tons of CO2, one tonne is 1.1 tons and with an exchange rate of 1.5, the US marginal cost of $100 US/ton is equal to 100*1.5*1.1/3.67 or $45 CDN/tonne of CO2. Such a cost would add $45 to the cost of a MWh of electricity from a coal plant and about $17 to the cost of a MWh of electricity from a CCGT plant. Such a cost would cause rapid substitution of CCGT for coal in electricity generation and raise the price of electricity to the six cent range where some renewables could compete. It seems unlikely, however, that the US and Canada will enact regulations so strict, given their profound impacts on the energy industries in North America. The $10 CO2 marginal cost seems a more plausible, but by no means easy, policy goal.

In summary, while there is considerable uncertainty, more rigorous control of the emission of SO2 and NOX could raise electricity prices by several dollars per MWh, while significant control of CO2 might add $10 per MWh or even more. The extent of cost increases will depend on the degree of control that is required. The small increases that may be associated with modest increases in the stringency of control over SO2 and NOX seem unlikely to significantly affect the competitive position of nuclear power. Vigorous control of carbon dioxide emissions, however, could raise the price of thermal electricity significantly. The limit on these costs at the present time appears to be the addition of new capacity utilizing combined cycle gas turbines, discussed below, which may cost $40/MWh to $50/MWh. (Gibbons and Bjorkquist, 1999, citing Nichols, Farr and Harrison, 1996, p. 40.) Such prices may still not make nuclear investment financially attractive. Cohn (1997, pp. 155, 283) concludes that nuclear power costs will have to decline by at least two cents per kWh ($20/MWh) before new nuclear plants can compete with other forms of generation, such as CCGT, and it seems unlikely that reasonable environmental costs will bridge this gap without very costly limits on CO2.

The MDC recommended that generators be allowed to market Agreen power@ that complies with the existing EcoLogo label (MDC, 1998b, RM 5-6) but this definition of green power does not include nuclear power. The MDC also recommended that all consumers be provided with a power label that indicated both the generation source (coal, nuclear, hydro, etc.) and the air emissions if any. (MDC, 1998b, RM 5-8.) This label will allow retailers to differentiate their power offerings from the power pool, and will give nuclear generation a chance to attract a premium price from those who are more worried about the air emissions from coal combustion than about the hazards of nuclear power. I have seen no studies of the price premium, if any, that nuclear power might attract, and it is possible that public opinion would cause nuclear to be sold at a discount.

VI. Cost Structure of Nuclear Power

The conventional wisdom has it that nuclear plants are capital intensive with high capital costs per MW of capacity but relatively low operating costs or at least relatively low fuel costs. Part of the reason for the high capital cost is the high level of environmental and occupational safety that must be built into the design, while part of the cost is accounted for by the inherent complexity of a nuclear plant. Another contributing factor is the long time between the first expenditures of substantial sums for design and environmental approval and the time when the plant begins to earn revenue; the interest in borrowed money during this period can represent a significant part of the final cost of the plant. As noted above, the long lead times also increase the uncertainty about the demand that will exist for the output of the plant, and increasing uncertainty will increase the risk premium that investors will demand. Finally, there are concerns about decommissioning costs and while estimates of these costs are available there has been little experience with the full decommissioning of nuclear plants and thus there is considerable uncertainty about the magnitude of these costs. The absence of any repository for the long-term storage of nuclear wastes adds to the uncertainty of future costs.

High capital costs and low operating costs mean that capacity utilization of the plant is the most important factor in determining its profitability. Such a plant should be available as much of the time as possible and should run at full capacity whenever it is available. The operator will submit low bids to ensure continual operation and manage the plant to maximize its availability.

While the routine operating costs of nuclear plants may often be low, some plants, including some CANDU plants, have experienced problems requiring very expensive renovation long before the design life of the plant has been reached. Some of OPG=s plants have required the replacement of the tubes that hold fuel bundles, an operation that is costly to perform and costly in the time that the unit is out of service. The model of nuclear costs might therefore be a model with low routine operating costs but high recurring maintenance costs.

VII. Future Electricity Price

The single most important factor driving future investment in nuclear generation or any other form of generation in Ontario is likely to be the price of electricity. Since generators have a choice of selling under contract or in the spot market, it seems unlikely that contract prices will deviate substantially and systematically from the expected spot price. So, we will focus here on the likely future for the spot price of wholesale electricity. As we look to the future it is worth remembering that electricity prices in North America have declined in real terms throughout much of this century except for the OPEC-affected period from 1974 through the early 1980's; Burtraw, Darmstadter, Palmer and McVeigh (1999) report that US electricity prices fell by 25% from 1983 to 1995 alone. In Ontario, real prices fell from early in the century to the mid-1970s, rose with energy prices but fell back below 1975 prices by the late 1980s, then jumped over 50% by 1995 .

The MDC noted that the retail price of electricity in 1998 averaged about 7.2 cents per kWh. This price, however, includes all costs of providing electricity to the end user: the cost of the power plus the cost of transmission and distribution including metering and billing. In a restructured electricity market, the retail price will be the sum of the wholesale price, a charge to cover stranded debt or competition transition charge (CTC), charges levied by the IMO for its operation and for other items to be paid for by all electricity users, a transmission charge and a distribution charge. The MDC estimated that if the wholesale power price was 3.8 cents, Ontario consumers would face prices no higher than they face today. (MDC, 1999, p. 2-4.)

In a competitive market, the spot price of electricity would depend on supply and demand, representing the short run marginal cost of the marginal unit dispatched at any point in time. When there is excess capacity, the spot price will be low, while if capacity is tight the spot price will rise. If we look at the annual average of the spot price, it should be near the marginal cost of a low-cost marginal plant such as a coal plant when there is excess supply and near the high end of the marginal cost of a more costly plant such as a high cost coal plant or a gas turbine plant when supply is short. The MDC examined the costs of OPG=s generation and concluded that the competitive price given the generation mix that would be available in the year 2000 and the next few years would likely be well below 3.8 cents/kWh. The Ontario Clean Air Alliance reported that a study commissioned by Ontario Hydro had estimated that the short-run marginal cost of Hydro=s coal plants could be as low as 2.5 cents/kWh. (Gibbons and Bjorkquist, 1999, p. 5.)

But OPG currently owns about 85% of the generation capacity in Ontario and has controlled the non-utility generator (NUG) contracts which represent perhaps another 5%. This is not a competitive market structure; on the contrary, OPG clearly has considerable market power. In recognition of this market power, the MDC negotiated a market power mitigation agreement which it recommended to the government. This agreement embodies three central features:

- $ The revenue earned by OPG is capped at 3.8 cents/kWh for the first four years after market opening, and perhaps longer. (MDC, 1999, RMs 1-2, 1-9.) If OPG earns more than 3.8 cents on a predetermined quantity of electricity representing 90 % of OPG=s estimated share of the Ontario market, it must rebate the excess on that 90% to all Ontario consumers in proportion to their kWh consumed.
- $ Within 42 months of market opening, OPG must decontrol all but 35% of the price-setting capacity in Ontario, with no other party acquiring more than 25%. (MDC, 1999, RMs 1-3, 1-7.) Decontrol may involve sales, long term leases or some other arrangements, but it must divest OPG of all control over the unit. This should ensure that within three and one-half years after market opening the market structure is reasonably competitive. Units that are decontrolled are no longer subject to the revenue cap.
- $ Within 10 years of market opening, OPG must decontrol all but 35% of **all** capacity in Ontario. (MDC, 1999, RM 1-6.) When this objective is achieved, any revenue cap regime still in operation will terminate.

This revenue cap agreement will not prevent OPG from using its market power to raise the wholesale price to 3.8 cents/kWh, but it will remove most of the profit from raising the price above that level. OPG=s strategy for profit maximization under this revenue cap may be to set prices that are expected to just exceed 3.8 cents for the year, on the grounds that variations in both supply and demand will make the annual revenue forecast uncertain and if they fall short of 3.8 cents there is no way to recoup the shortfall. Consumers would therefore receive a small rebate each year. The effective consumer price will likely average about 3.8 cents for the first few years until the decontrol target is largely achieved.

Once the decontrol of price-setting plant is achieved, prices should reflect short run marginal costs which will depend on supply and demand. If NAOP is successful and most of the seven nuclear units that were laid up in 1998 and 1999 come back on stream, competitive prices should be below 3.8 cents until demand growth has outstripped this capacity. If NAOP is only modestly successful and if the economy grows for a few years, the competitive price could be closer to 3.8 cents. In the longer run, the price must rise to a level that will pay the full average costs of new generation. Some observers have suggested that the all-in cost of power from a new CCGT cogeneration unit with a well-matched steam load might be no more than 3.8 cents. This might represent the proposed cogeneration plant for the refineries in Sarnia. On the other hand, one analysis suggests that the full costs for a new CCGT by itself would be 4.86 cents/kWh. (Gibbons and Bjorkquist, 1999, p. 5, citing Nichols, Farr, and Harrison, Jr., 1996.) Of course any gas-fired projects depend heavily on the price of gas which has risen considerably during 1999. The MDC heard vigorous representations from representatives of the independent power producers (IPPSO) that new generation plants would not be built for a price of 3.8 cents. While claims by producers that they need higher prices might warrant careful scrutiny, a price higher than 3.8 cents may indeed be needed to achieve significant investment in new capacity, or at least to secure investment once the well-balanced cogeneration projects have been exhausted. If so, it would be inefficient to build such plants until one expects the price to be above the forecast full cost of the new generation. The nice thing about a competitive market is that no regulator or public body will have to make decisions based on this thin evidence; investors will make their own decisions and live with the consequences.

Another factor influencing the price of electricity in Ontario will be trade with neighbouring jurisdictions. The existing interties with other jurisdictions currently have a total capacity of about 4,000 megawatts, roughly 20 percent of peak Ontario demand although some of this capacity is consumed in loop flows around Lake Erie so that not all of it is available for economic transactions. Part of the market power mitigation agreement involves a commitment by Servco to make best efforts to increase this capacity by 50 percent to 6,000 megawatts. (MDC, 1999, ch. 2, RM 1-5.) These interties provide the ability to import electricity when the price is higher in Ontario than elsewhere and to export electricity when the price here is lower than elsewhere, a practice that currently benefits both OPG and our neighbours. Historically imports and exports have tended to cancel each other out over the course of several years, with import predominating during the heating season to satisfy the Ontario winter peak demand and exports predominating during the air conditioning season to satisfy the US summer peak demand. If US prices are persistently above or below Ontario prices, this electricity trade will tend to pull our prices up or down toward the US price. The MDC heard arguments both ways; increased intertie capacity would allow high prices in the US to drive up Ontario power prices as Ontario generators exported low cost Ontario power; and increased intertie capacity would allow low cost dirty coal plants in the Ohio valley to export power to Ontario, lowering our electricity prices and increasing the air pollution flowing across the border from the Ohio valley.

Happily, one need not worry about both problems, at least not at the same time. It seems most likely that the interties will be used mostly for short-term imports and exports when peak demands and capacity availability do not coincide on both sides of the border, thus shaving peak prices in all trading jurisdictions. In addition, if there is a consistent price advantage on one side of the border or the other, there should be a general flow from the lower price to the higher price jurisdiction. I have seen no published analysis that confidently predicts which way this flow would go, perhaps because it would, of course, depend on all of the hard-to-predict factors discussed above for both Ontario and the neighbouring jurisdictions. No doubt consultants are now busily performing precisely these calculations for the principal affected parties.

The MDC also heard arguments, most vigorously presented by and on behalf of IPPSO, that the debt from Ontario Hydro should mostly be loaded onto OPG and that little or none of it should be treated as stranded debt to be paid off by a levy on all electricity consumption. The logic of the argument was that if OPG was assigned too little debt it would be able to set low prices and still make money and that the resulting low prices would discourage new investment in generation. This argument would make good sense in the world of a regulated monopoly where the generator has market power sufficient to choose the price or where a regulator will set a price that covers all reasonable costs. However if OPG does achieve the decontrol targets set in the Market Power Mitigation Agreement, and if the resulting market structure is reasonably competitive, then the amount of debt carried by OPG should have no effect on the price of electricity. A competitor cannot do better than to bid its marginal costs. So, the argument that OPG debt affects the electricity price carries weight in the long run only if the government, as shareholder of OPG, fails to instruct it to achieve the decontrol targets. In the short run OPG does have market power but the revenue cap sets both the ceiling and a probable floor on the wholesale price.

VIII. Conclusions

This review leads to several conclusions regarding the future of nuclear power in a restructured electricity market:

- Investment in new nuclear plants or in the renovation or life extension of existing nuclear plants should be based on an economic analysis of the profitability of that investment.
- The price of wholesale power in Ontario is likely to average close to 3.8 cents for the first few years of market operation. After that, if a competitive generation structure has been achieved, the price may fall if demand grows slowly and if most of the nuclear units return

to service, while if demand grows quickly and many of the nuclear units are not returned to service the price could rise above 3.8 cents.

$ It appears that CCGT and CCGT cogeneration are the principal candidates for new generation capacity. This means that the cost of nuclear investments in the medium and long term should be judged against the forecast cost of generation from these gas-fired technologies.

$ Modest regulation of air emissions from electricity generation will not likely raise thermal generation costs substantially. On the other hand, aggressive regulation of the emission of carbon dioxide could add $10 per MWh or more to the cost of thermal generation, thus improving the prospects for nuclear and for renewable technologies including hydroelectric, solar and wind. However it seems unlikely that highly costly regulations could be imposed on electricity generation without similar requirements for other major sources of the same pollutants, which would require very broad political support.

$ Trade with the US will affect Ontario=s electricity prices more than in the past, but it is not clear at present whether this will pull Ontario prices up or down from the prices that would exist in the absence of trade.

These conclusions depend in part on the design of the restructured market. This paper has assumed that the MDC design will be implemented. Important deviations from the MDC design could affect some of these conclusions. For example, allowing embedded generation to bypass transmission charges will raise transmission charges for all other consumers and encourage uneconomic new generation investment, reducing demand and price for existing power sources.

References

ACCOES, Advisory Committee on Competition in Ontario=s Electricity System, 1996, AA Framework for Competition,@ Toronto: Ministry of Environment and Energy, (MacDonald Committee Report).

Applied Decision Analysis, 1983, AAnalysis of Power Plant Construction Lead Times, Vol. 1, Analysis and Results,@ Final Report EPRI, EA-2880.

Barker, James, Bernard Tenenbaum and Fiona Wolf, 1997, AGovernance and Regulation of Power Pools and System Operators: International Comparisons,@ World Bank Technical paper no. 382, Washington: World Bank.

Burtraw, Dallas and Michael Toman, 1998, AThe Benefits of Reduced Air Pollutants in the U.S. from Greenhouse Gas Mitigation Policies,@ Resources for the Future Discussion Paper 98-01-REV.

Burtraw, Dallas, Joel Darmstadter, Karen Palmer, and James McVeigh, 1999, ARenewable Energy: Winner, Loser or Innocent Victim?@ *Resources* 135, pp. 9-13.

Cohn, Steven Mark, 1997, *Too Cheap To Meter,* Albany: State University of New York Press.

Daniels, Ronald J., ed., 1996, *Ontario Hydro at the Millennium: Has Monopoly=s Moment Passed?* Kingston: McGill-Queen=s University Press.

Dewees, Donald, 1996, ANuclear Environmental Consequences,@ in Ronald J. Daniels, ed., *Ontario Hydro at the Millennium: Has Monopoly=s Moment Passed?* Kingston: McGill-Queen=s University Press.

Diener and Acres, 1998, AEmissions Reduction Study for the Ontario Clean Air Alliance (OCAA),@ Toronto: Ontario Clean Air Alliance.

Gibbons, Jack and Sara Bjorkquist, 1999, AThe Ontario Energy Board=s Draft Standard Supply Service Code: Effects on Air Quality@ submission to the OEB re: RP-1990-0040.

Helm Dieter and Tim Jenkinson, 1997, AThe Assessment: Introducing Competition into Regulated Industries,@ *Oxford Review of Economic Policy* 13:1, pp. 1-14.

Hunt, Sally and Graham Shuttleworth, 1996, *Competition and Choice in Electricity*, Toronto: Wiley.

Joskow, Paul L., 1997, ARestructuring, Competition and Regulatory Reform in the U.S. Electricity Sector,@ *Journal of Economic Perspectives* 11:3, pp. 119-138.

Krupnick, Alan and Virginia McConnell, 1999, ACost-Effective NOX Control in the Eaastern U.S., Washington: Resources for the Future; presented at the AERE Workshop, Cambridge, Mass., July, 1999.

Market Design Committee, 1998a, AFirst Interim Report of the Market Design Committee@ Report to the Honourable Jim Wilson, Minister of Energy, Science and Technology@ March 30.

Market Design Committee, 1998b, ASecond Interim Report of the Market Design Committee@ Report to the Honourable Jim Wilson, Minister of Energy, Science and Technology@ June 30.

Market Design Committee, 1998c, AThird Interim Report of the Market Design Committee@ Report to the Honourable Jim Wilson, Minister of Energy, Science and Technology@ October 8.

Market Design Committee, 1999, AFinal Report of the Market Design Committee@ Report to the Honourable Jim Wilson, Minister of Energy, Science and Technology@ January 29.

Nichols, Albert, and David Harrison, Jr., 1990, AThe Impact on Ontario Hydro of Emissions Trading for Nitrogen Oxides: A Preliminary Analysis,@ Report to Ontario Hydro, Cambridge, Mass.: NERA.

Nichols, Albert, John Farr, and David Harrison, Jr., 1996, AThe Timing of Plant Replacement and the Cost-Effectiveness of CO2 Reductions from Two Canadian Utilities,@ Cambridge, Mass.: NERA.

OECD, 1997, *The OECD Report on Regulatory Reform, Vol. I: Sectoral Studies, #4 Electricity,* Paris: OECD.

Ontario, 1997, ADirection for Change: Charting a Course for Competitive Electricity and Jobs in Ontario,@ Toronto: Ministry of Energy, Science and Technology, (White Paper).

Ontario Energy Board, 1999, AStandard Supply Service Code: Staff Draft for Consultation Purposes,@ OEB, 29 January.

Ontario Hydro, 1990, *Annual Report 1989,* Toronto: Ontario Hydro.

Ontario Hydro, 1993, Full-Cost Accounting for Decision Making, Survey Team #4, Task Force on Sustainable Energy Development.

OTAG Control Technologies & Options Workgroup, 1996, AStates= Report on Electric Utility Nitrogen Oxides Reduction Technology Options for Application by the Ozone Transport

Assessment Group,@ OTAG, accessed Aug. 25, 1999 at www.epa.gov/ttnotag1/otag/finalrpt/chp5/appa.htm.

Ottinger, R.L., D.R Wooley, N.A Robinson, D.R Hodas, S.E Babb, 1990, *Environmental Costs of Electricity*, Pace University Center for Environmental Legal Studies, Oceana Publications.

Smith, Anne E., Jeremy Platt, A. Denny Ellerman, 1998, AThe Costs of Reducing Utility SO2 Emissions - Not as Low as You Might Think,@ Cambridge: MIT Center for Energy and Environmental Policy Research, WP 98-010.

Sweet, William, 1997, AA Nuclear Reconnaissance,@ *IEEE Spectrum* 34:11, pp. 23-28.

Table 1
Ontario Demand by Customer Classes (Approx)
(tWh, 1997)

Customer Class	Ontario Hydro (Servco)[1]	MEUs[2]	Total	
			tWh[3]	%
Large (>5 MW)	19.2	12.6	31.8	25
General Service (<5 MW)	Retail 18.8	54.2	62.5	48
Residential		24.8	35.3	27
Other	MEUs 95.3	0.6		
Total		92.2	129.1	100

1 From Ontario Hydro 1998 Annual Report
2 From MEUs - OEB
3 From Ontario Hydro report and MEU data. Approximate only.

Table 2
Air Emission Coefficients and Costs
Ontario Hydro Thermal Plant Averages

	Sulphur Dioxide	**Nitrogen Oxides**	**Carbon Dioxide**
Emission coefficient (kg/MWh)[1]	4.41	2.52	974
Average control cost ($/MWh)[2]	1.35	4.50	9.74
Average control cost using gas conversion ($/tonne)[3]	625	1185	4.67

[1] Weighted average, Ontario Hydro thermal plants. Diener and Acres (1998, p. 12).
[2] SO2 assumes $200/ton US control cost based on Smith, Platt and Ellerman (1998, 13) who estimate that the long run average cost of SO2 control in the United States under Phase II of the Clean Air Act Title IV program may be about $200 US per ton, equal to about $330 CDN/tonne. OTAG (1996, p. 6) report NOX reductions of over 65% at less than $700 (US) per ton, and state that most technologies would cost less than 0.3 cents per kWh, equal to $4.50 CDN per MWh. Carbon dioxide assumes $10 per tonne of CO2 abatement cost.
[3] Based on Diener and Acres (1998, p. 16) who present the cost per tonne of controlling various pollutants from coal-fired plants by switching to CCGT generation technology. They attribute the cost separately to each pollutant. The data presented here result from dividing their costs by 3 to allocate (arbitrarily) the cost of gas conversion equally to these three pollutants. Note that the sulphur dioxide and NOX costs are greater than the costs presented in note 2 above while the carbon dioxide costs are less. To the extent that the switch to gas is motivated in part by concern for other pollutants, the costs attributed to these three pollutants should be reduced.