EB-2007-0707

ONTARIO ENERGY BOARD

IN THE MATTER OF sections 25.30 and 25.31 of the *Electricity Act, 1998* (S.O. 1998, c. 15, Schedule A);

AND IN THE MATTER OF an Application by the Ontario Power Authority for review and approval of the Integrated Power System Plan and proposed procurement processes (the "IPSP and Procurement Process Application").

POLLUTION PROBE
DOCUMENT BOOK FOR ISSUES SUBMISSIONS

January 15, 2008

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EB-2007-0707

IPSP ISSUES HEARING

Speaking Notes for Jack Gibbons

January 15, 2008

Thank you for the opportunity to make submissions to you about the Issues List for the IPSP hearing.

I will be making submissions on the following issues:

1. Marginal or Full Cost Pricing;
2. The Coal Phase-Out;
3. The Cost of capital;
4. Avoided Costs;
5. the OPA's so-called "Directive Priorities";
6. the OPA's definition of base-load

Marginal/Full Cost Pricing

Let's begin with marginal or full cost pricing.

Energy conservation is the Government's top priority to meet Ontario's electricity service needs. However, there is no discussion in the IPSP of removing the subsidies for electricity consumption and raising the price of electricity up to its full or marginal cost. This is a huge gap since full cost pricing is the single most powerful and cost-effective tool to promote energy conservation. It is also a prerequisite for creating a competitive electricity market.

As the Board is well aware, the IPSP Regulation requires the OPA to:

"4. Identify and develop innovative strategies to encourage and facilitate competitive market-based responses and options for meeting overall system needs.

5. Identify measures that will reduce reliance on procurement under Section 25.32 of the Act."

It is Pollution Probe's submission that a move to marginal or full cost pricing is the most cost-effective and prudent strategy to achieve these objectives.

In addition, there is no discussion of the cost and benefits of eliminating bulk metering despite the fact that it has been estimated that approximately 1.4 million apartment and condominium units do not have individual metering. As a result the direct cost of electricity for approximately 1.4 million homes is virtually zero.

Therefore, it is our submission that the issues list should include the following issues:

First, should the OPA develop a plan to move Ontario to marginal or full cost pricing?

Second, should bulk metering be eliminated?

Yesterday Mr. Zacher of the OPA asserted that full cost pricing is beyond the scope this hearing, but he gave no justifications for his assertion. [Tr. Vol. 1, p. 95] It is Pollution Probe's submission that an economic regulator cannot ignore this issue that is so central to its mandate to ensure that the IPSP is prudent and cost-effective.

The Coal Phase-Out

I would now like to turn to my favourite topic – the coal phase-out.

According to the Government's directive to the OPA, it must develop a "Plan for coal-fired generation to be replaced by cleaner sources in the earliest practical time frame that ensures adequate generation capacity and electricity system reliability in Ontario."

The good news is that, if the OPA's forecasts are correct, Ontario can eliminate the need for energy production from its coal-fired power plants by 2010.

However, under the OPA's plan, our coal plants will continue to produce substantial quantities of energy until the end of 2014. Specifically, the OPA is proposing that

we continue to dispatch our coal plants in advance of our natural gas-fired power plants; and that we continue to make non-emergency coal-fired electricity exports to the U.S. Therefore, it is our submission that the IPSP is not consistent with the Government directive to phase-out coal generation as soon as practically possible. Therefore it is our submission that the following issues should be added to the issues list:

First, should Ontario ban non-emergency coal-fired electricity exports?

Second, commencing in 2010 should Ontario dispatch gas-fired generation in advance of coal-fired generation to meet our domestic electricity needs?

Needless to say, under these scenarios, our coal plant capacity can continue to be part of Ontario's reserve margin until December 31, 2014.

According to the OPA's counsel, Mr. Vegh, our proposed additional issues are outside the scope of the Government's directive to the OPA. We completely disagree with Mr. Vegh on this issue. If the Government's coal phase-out directive simply said develop a plan to replace coal-fired generating capacity by December 31, 2014 then Mr. Vegh would be correct. However, that is not what the directive says. The directive says replace coal-fired generation as soon as practically possible. Coal-fired generation is not coal-fired generating capacity. That is, coal-fired generation is kWh, not kW.

To quote from the OPA's December 2005 *Supply Mix Advice Report*, electricity generation is:

"The process by which electrical energy is produced by transforming other forms of energy. Electric energy is commonly expressed in kilowatthours (kWh) or megawatthours (MWh)."

Mr. Vegh in his submissions yesterday gave three reasons why the OEB should not accept our proposed additions to the Issues List.

First, according to Mr. Vegh, changing the dispatch order would be a dramatic shift in Government policy. [Tr. Vol. 1, p. 45] We disagree. It has been Government of Ontario policy to phase-out coal since September 2002. Furthermore, Premier McGuinty has won two back to back

majority governments on the promise to phase-out coal. It is not Pollution Probe that is proposing to shift government policy. Rather we are proposing to implement government policy by changing the dispatch rules for our coal plants. Furthermore, dispatching cleaner gas-fired generation in advance of our dirty coal plants has been done before in Ontario and it can be done again. Specifically, commencing in the year 2000, OPG adopted the policy of dispatching its Lennox gas-fired power plant ahead of its Lakeview coal-fired units on smog alert days. I have provided the Board, the OPA and other intervenors with copies of my correspondence with OPG with respect to the dispatch order for Lennox and Lakeview.

Second, according to Mr. Vegh, the Government's directives do not explicitly ask the OPA to develop an environmental dispatch system. [Tr. Vol. 1, p. 46] This is

true. But it is also irrelevant, since the Government's directive does ask the OPA to develop a plan to phase-out coal generation as soon as practically possible. As a consequence, intevenors have the right to ask if Ontario can speed up the coal phase-out by changing the dispatch rules. If the OEB puts this issue on the issues list, we will file expert evidence on this topic which can be tested under cross-examination by the OPA and other intervenors. Everyone, including the OPA, will have the opportunity to cross-examine and submit arguments on this issue. And the OEB will ultimately decide if our proposals are a practical option to speed up the coal phase-out. By asking the OEB to put these issues on the Issues List, we are simply asking for our day in court.

Finally, Mr. Vegh argues that changes to the dispatch rules are beyond the scope of this hearing because they are a

"today problem". [Tr. Vol. 1, p. 46] Once again, Mr. Vegh is trying to reword the directive. As I have already noted, the Government's directive does not say develop a strategy to phase-out coal capacity seven years from now. On the contrary, the directive says phase-out coal generation as soon as practically possible. That is, the Government is very explicitly saying that coal generation is a "today problem" that it wants to be solved as soon as practically possible.

For all of the above reasons, it is our submission that the issues list should include the following issues:

First, should Ontario ban non-emergency coal-fired electricity exports?

Second, commencing in 2010 should Ontario dispatch gas-fired generation in advance of coal-fired generation to meet our domestic electricity needs?

In addition, to complete the coal phase-out, the OPA is proposing to procure 1350 MW of inefficient, simple-cycle gas generation. This new generation will have a capital cost of approximately $900 million and will be idle for 97.5% of the year in 2015. Surely there are lower cost options to meet our peak day demands.

Therefore, it is our submission, that the issues list should include the following issue:

Are there lower cost options that can completely or partially reduce the need for 1350 MW of simple-cycle gas generation?

Potentially lower cost options that should be considered include demand response, energy conservation, renewable energy, end-use fuel switching, combined heat and power, combined-cycle generation and the conversion of one or more of OPG's coal boilers to burn cleaner fuels.

As the Board is aware, part of the OPA's rationale for these simple cycle gas plants is to avoid the need for transmission system reinforcements in transmission constrained regions of the province. Therefore building combined heat and power plants in these regions can simultaneously help to avoid the need for new transmission capacity and meet part of our base-load supply needs.

Cost of Capital

I would now like to turn to the cost of capital issue. The OPA has evaluated the relative economics of the various supply and conservation options using a **uniform** real rate of return on capital of only 4%.

It is our submission that this assumption is inappropriate for the following reasons.

First, it seriously underestimates the opportunity cost of capital for the Ontario economy. [Treasury Board of Canada, *Canadian Cost-Benefit Analysis Guide*, (2007), page 37]

Second, using a uniform cost of capital for all the supply and conservation options, ignores the fact that some options

are riskier than others, and as a consequence, have higher risk-adjusted costs of capital.

In short, the OPA's decision to evaluate all resource options using a uniform 4% real cost of capital biases its analysis in favour of capital-intensive and high-risk options.

Therefore it is our submission that the issues list should include the following issues:

First, what is the appropriate minimum rate of return on capital for evaluating the resource options in the IPSP? Second, should higher rates of return on capital be used to evaluate the cost-effectiveness of relatively high-risk

resource options? And if not, how should the IPSP quantify the risk profiles of the various resource options?

Avoided Costs

I would now like to turn to the avoided cost issue. The OPA evaluates the cost-effectiveness of energy conservation, demand response, renewable energy, end-use fuel switching and combined heat and power by comparing their costs to the avoided costs of conventional grid-supplied generation.

Therefore, it is essential that the OPA's avoided cost estimates accurately reflect the marginal costs of conventional grid-supplied generation. As the Board is well aware, nuclear power is the dominant source of grid-supplied generation in the IPSP. Therefore, to accurately

estimate the cost-effectiveness of the alternatives to more grid-supplied electricity, the OPA must accurately estimate the cost of new nuclear power plants.

It is our submission, that it appears, that the OPA has underestimated the costs of new nuclear power plants in at least three respects.

First, by assuming that the required rate of return on capital for new nuclear power plants is only 4%.

Second, by underestimating the capital costs of building new nuclear power plants. [$2,907 per kW (Ex. G, Tab 2, Sch. 1, p. 7; vs. Darlington cost of $4,085 per kW (1993$) (Rolling the Dice, page 10). That is, approximately 30% less despite CPI increase of 25%]

Third, by overestimating the average capacity utilization rates of new nuclear power plants. To be specific, the OPA's plan assumes that new nuclear power plants will have an average annual capacity factor of 90% despite the fact that in 2007 the capacity factor of our nuclear fleet was only 67%.

Therefore it appears to us that by underestimating the cost of nuclear power, the OPA has also underestimated the cost-effectiveness of conservation, demand response, renewable energy, end-use fuel switching and combined heat and power.

Therefore, it is our submission, that the following issue should be added to the Issues List:

Are the avoided cost estimates reasonable?

The OPA's "Directive Priority"

I would now like to turn to the OPA's so-called "Directive Priority".

According to the OPA, its Directive Priority is as follows:

1. Mazimize cost effective conservation
2. Maximize cost effective renewables
3. Make up our remaining base-load requirements with nuclear power.

We agree that the OPA's first two priorities are consistent with the Government's directives. However, we do not believe that the Government's directives entail that natural gas-fired combined-cycle or combined heat and power

generation cannot be used to meet some of Ontario's base-load needs.

In particular, we would like to draw the Board's attention to the following facts.

First, the Government directives to the OPA do not state that natural gas generation cannot be used for base-load.

Second, according to the Government's directive to the OPA, the IPSP is to: "pursue applications that allow high efficiency" natural gas fired generation.
Natural gas combined-cycle and combined heat and power plants can achieve their highest efficiencies as base-load plants. Therefore if the OPA is to pursue applications that

allow gas to be used as efficiently as possible then it must permit natural gas generation to be used for base-load.

Third, it is important to note that the Government's directives do not specify a cap on the maximum amount of natural gas-fired generation that can be used for base-load or any other purpose.

Fourth, nuclear power, on the other hand, is subject to two pre-determined caps. Specifically, the Government's directive says that nuclear must only be used for base-load. In addition, it says that nuclear's contribution to meeting our base-load needs cannot exceed 14,000 MW.

In short, it is our submission that the Government's directives do not preclude the use of high-efficiency natural

gas-fired generation to meet some of Ontario's base-load needs.

Therefore, it is our submission that the following issue should be added to the Issues List: Is the so-called "Directive Priority" consistent with the Government's directives to the OPA?

The OPA's definition of base-load

Finally, I would like to turn to the OPA's definition of base-load.

According to the OPA's definition of base-load, base-load is all supply that can be met by nuclear generation at a lower cost than natural gas-fired combined-cycle generation. Furthermore, based on its optimistic assumptions about the cost of new nuclear power plants,

the OPA concludes that Ontario's base-load requirements will equal 19,000 MW in 2015. [Ex. D, Tab 3, Sch. 1, Attachment 1, page 13]

It is Pollution Probe's submission that while the OPA's definition of base-load is novel; it is also completely inconsistent with the conventional definition of base-load and the Government's directive.

As the Board is well aware, Ontario's base-load needs are substantially less than 19,000 MWs. To be specific, they are equal to our minimum continuous load over a year. In 2006 this was 11,621 MW.

And as we have already noted, according to the Government's directives to the OPA, nuclear generation is

to be used only to meet Ontario's base-load electricity requirements. As a result, the definition of base-load has important implications for the amount of new nuclear generation that can be built to meet Ontario's future electricity needs.

Therefore it is our submission that the issues list should include the following issue:

> Is the IPSP's definition of base-load consistent with the Government's directive to the OPA?

Thank you for your attention. If you have any questions, I would be pleased to answer them.

June 13, 2006

Dr. Jan Carr
Chief Executive Officer
Ontario Power Authority
1600-120 Adelaide Street West
Toronto, Ontario
M5H 1T1

Dear Dr. Carr:

Re: Integrated Power System Plan

As authorized by the Lieutenant Governor in Council under Section 25.30 of the *Electricity Act, 1998*, I am providing direction for the preparation of the Integrated Power System Plan.

The Government directs the OPA to create an Integrated Power System Plan to meet the following goals:

1. The goal for total peak demand reduction from conservation by 2025 is 6,300 MW. The plan should define programs and actions which aim to reduce projected peak demand by 1,350 MW by 2010, and by an additional 3,600 MW by 2025. The reductions of 1,350 MW and 3,600 MW are to be in addition to the 1,350 MW reduction set by the government as a target for achievement by 2007. The plan should assume conservation includes continued use by the government of vehicles such as energy efficiency standards under the *Energy Efficiency Act* and the Building Code, and should include load reduction from initiatives such as: geothermal heating and cooling; solar heating; fuel switching; small scale (10 MW or less) customer-based electricity generation, including small scale natural gas fired co-generation and tri-generation, and including generation encouraged by the recently finalized net metering regulation.

2. Increase Ontario's use of renewable energy such as hydroelectric, wind, solar, and biomass for electricity generation. The plan should assist the government in meeting its target for 2010 of increasing the installed capacity of new renewable

.../cont'd

energy sources by 2,700 MW from the 2003 base, and increase the total capacity of renewable energy sources used in Ontario to 15,700 MW by 2025.

3. Plan for nuclear capacity to meet base-load electricity requirements but limit the installed in-service capacity of nuclear power over the life of the plan to 14,000 MW.

4. Maintain the ability to use natural gas capacity at peak times and pursue applications that allow high efficiency and high value use of the fuel.

5. Plan for coal-fired generation in Ontario to be replaced by cleaner sources in the earliest practical time frame that ensures adequate generating capacity and electricity system reliability in Ontario.

   The OPA should work closely with the IESO to propose a schedule for the replacement of coal-fired generation, taking into account feasible in-service dates for replacement generation and necessary transmission infrastructure.

6. Strengthen the transmission system to:

   - Enable the achievement of the supply mix goals set out in this directive;
   - Facilitate the development and use of renewable energy resources such as wind power, hydroelectric power and biomass in parts of the province where the most significant development opportunities exist;
   - Promote system efficiency and congestion reduction and facilitate the integration of new supply, all in a manner consistent with the need to cost effectively maintain system reliability.

7. The plan should comply with Ontario Regulation 424/04 as revised from time to time.

Yours sincerely,

Dwight Duncan
Minister of Energy

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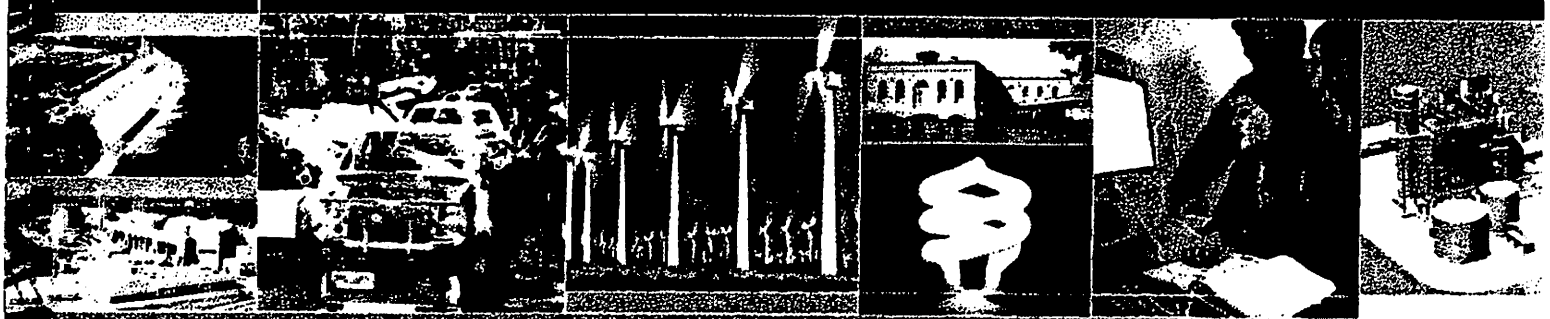
ONTARIO POWER AUTHORITY

1 Supply Mix Advice Report

Volume 1 – December 2005



OPA

Ontario Power Authority

1.6 Glossary of Terms

Acid rain	Precipitation containing nitric and sulfuric acids formed primarily by sulfur dioxide and nitrogen oxides released into the atmosphere by the burning of fossil fuels.
Advanced coal technologies	Technologies designed to enhance both the efficiency and environmental acceptability of coal extraction, preparation, and use.
Aggregators	Companies that buy or broker electricity on behalf of contracted retail customers. They may also offer capacity for demand response to the market.
Alternating current (AC)	An electric current that reverses its direction at regularly recurring intervals.
Ancillary service	Functions required to support the reliable operation and security of the transmission and generation system. They are coordinated by the IESO and include various types of operating reserves and spinning reserve, frequency and voltage control and black-start capability.
Appliance	Ordinarily self-contained equipment powered by electricity that is used to perform an energy-driven function. Common appliances include refrigerators, clothes washers, conventional ranges/ovens and microwave ovens, toasters, radios, and televisions. Not included in this definition are central heating or cooling components.
Appliance efficiency standards	Specifications that set prescribed minimum energy efficiency of classes of appliances (may be voluntary or mandatory).
Average weather	The average temperature, humidity, wind speed, cloud index, etc, for a given day, month or year.
Backup generator	A generator used in the event of an emergency, such as a power shortage, to meet customer load requirements.
Backup power	Electric energy supplied by a utility to replace power and energy lost during an unscheduled equipment outage or when the power to meet demand is not available.
Base load	The minimum continuous load over a given period of time.

Base-load plant	A plant which is normally operated continuously and at a constant rate, to meet all or part of the minimum load of a system.
Bilateral electricity contract	A direct contract between an electric power producer and either an end-user or broker acting on behalf of an end-user.
Biomass	Organic non-fossil material available on a renewable basis, as long as the rate of extraction is equal to or less than the rate of replenishment. Biomass includes plant fibre such as wood, agricultural waste, manure, and other living-cell material that can be burned to produce heat energy.
Bottoming cycle	The process of recovering waste-heat to produce steam in a boiler, capturing the unused energy to drive a steam turbine generator to produce electricity.
Capacity	The maximum power output for which a generating unit, generating station or electricity producing apparatus is rated. Common units include kilowatts (kW), megawatts (MW) or gigawatts (GW). Also used to refer to the maximum potential output for the entire electricity system.
Capacity factor	The ratio of the electrical energy produced by a generating unit for a period of time to the electrical energy that could have been produced at continuous full power operation during the same period. It is usually expressed as a percentage.
Carbon dioxide (CO_2)	A colorless, odorless, non-poisonous gas naturally occurring in the Earth's atmosphere, and as a by-product of fossil fuel combustion. CO_2 is a greenhouse gas as it traps heat (infrared energy) radiated by the Earth into the atmosphere and thereby contributes to the potential for global warming. The global warming potential (GWP) of CO_2 is assigned a value of 1, and it is the gas by which the GWP of other greenhouse gases is measured.
Carbon dioxide equivalent (CO_2e)	A metric measure used to compare the emissions from various greenhouse gases based upon their global warming potential (GWP). Carbon dioxide equivalents are expressed as tones of carbon dioxide equivalents (tones CO_2e), and may be expressed in relation to other metrics, such as megawatt hours of electricity. The carbon dioxide equivalents for other gases are found by multiplying tones of the gas by its associated GWP.

Direct load control	Program activities that can interrupt customer load at the time of seasonal peak load by direct control of the power supply to individual appliances or equipment on the customer's premises. This function is normally carried out by the system operator and usually involves residential customers.
Dispatch	The process by which a system operator, such as the IESO, directs the real time operation of a supplier or a purchaser to cause a specified amount of electric energy to be provided to or taken off the system.
Dispatchable	A Generator or Load that is capable of responding to real-time control from a system operator such as the IESO.
Distributed generation (DG)	Electricity generating capacity located close to the customers it serves.
Distribution	The delivery of energy to retail consumers connected to the low-voltage (50kV or less) power system.
Distributor	Any entity that owns and is responsible for the maintenance of local distribution network systems that connect the bulk transmission grid to the end-use customer.
District heat	Steam or hot water produced in a central co-generation plant is piped into buildings as an energy source.
Diversity of supply	Spreading of risk by placing assets in several categories of (generation) investments or within a broad range of resources in one portfolio.
Dual-fired unit	A generating unit that can produce electricity using two or more input fuels.
Effective Capacity	Generation capacity available to meet demand during peak use periods.
Electric power	The rate at which electric energy is transferred, measured in capacity and commonly expressed in kilowatts (kW) or megawatts (MW)
Electricity Restructuring Act (Bill 100)	Provincial legislation, enacted in 2004, which created the Ontario Power Authority, and redefined the roles and responsibilities of the Independent Electricity System Operator and the Ontario Energy Board.
Electricity generation	The process by which electrical energy is produced by transforming other forms of energy. Electric energy is commonly expressed in kilowatthours (kWh) or megawatthours (MWh).

Appendix D - Glossary

Base Load

The minimum continuous load over a given period of time.

Biomass

Energy resources derived from organic matter, including wood, agricultural waste, and other living-cell material that can be burned to produce heat energy.

Capacity

The maximum power output for which a generating unit, generating station or other electrical apparatus is rated. Common units include kilowatts (kW) and megawatts (MW). Also used to refer to the maximum potential output for the entire electricity system.

Co-generation

The combined production of electricity and useful heat. Co-generation is often employed at industrial plants where the heat produced to generate electricity can be utilized subsequently in the manufacturing processes and for general space heating. Co-generation facilities use significantly less fuel to produce electricity and thermal energy than would be needed to produce them separately.

Combined Cycle Gas Plant

An electricity generating station that uses waste heat from its gas turbines to produce steam for conventional steam turbines.

Conservation

Any activity which reduces the amount of electricity used overall, or shifts the consumption of the electricity from a peak time to a time of lower demand.

ONTARIO CLEAN AIR ALLIANCE

June 23, 2000

Mr. Jim Burpee
Senior Vice President
Ontario Power Generation
Fax: 592-5136

Dear Jim:

I am writing to seek clarification with respect to the Honourable Dan Newman's statement that the Lennox Generating Station will be dispatched before the Lakeview Generating Station on smog alert days.

In particular, could you provide me with answers to the following questions.

1. What is OPG's definition of a "smog alert" day? Is a Ministry of the Environment "smog watch" advisory a "smog alert" day? Is a Ministry of the Environment "smog advisory" a "smog alert" day?

2. Will Lennox be dispatched before Lakeview when there is a smog alert day anywhere in Ontario or only if there is one in the GTA or Toronto?

3. On a smog alert day will Lennox be operated at its full capacity, 2140 MW, before Lakeview is dispatched?

4. On a smog alert day will Lennox be burning only natural gas?

Yours sincerely,

Jack Gibbons
Chair

cc. The Honourable Dan Newman
Tony Rockingham

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Fax'd July 10/00

ONTARIO POWER GENERATION

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Senior Vice Pr

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Mr. Jack Gibbons, Chair
Ontario Clean Air Alliance
625 Church Street
Suite 402
Toronto, Ontario
M4Y 2G1

July 7, 2000

Dear Mr. Gibbons:

I refer to your letters of June 23, 2000.

In one letter you seek clarification of Ontario Power Generation's decision to dispatch Lennox Generating Station ahead of Lakeview Generating Station in response to air quality index (AQI) alerts during 2000.

During the summer of 2000, Ontario Power Generation will commit Lennox units ahead of Lakeview units, reversing the normal economic dispatch order, based on the Ministry of the Environment's determination that the "tomorrow" AQI forecast for Toronto or Halton-Peel will be poor. The definitions you seek are explained on the MOE website. On these AQI alert days, Lakeview units will be committed only to meet Ontario's primary demand, obligatory reserve requirements, and previously committed sales. No additional sales will be made if Lakeview generation is required to support them. Lennox will usually be operated on natural gas, if it is available.

This voluntary initiative is in addition to our on-going obligation to respond to the Air Pollution Index (API) Alerts. It is worth noting, however, that an API alert has not occurred in the Etobicoke, Mississauga area in over a decade, reflecting the Ministry of the Environment's observation that air quality in Ontario is improving.

A simplistic full dispatch of Lennox GS before any Lakeview units are dispatched is not possible for three reasons. First, the rate of increase in demand and the Independent Market Operator's mandate to maintain adequate security of supply typically dictates that several plants across the province begin loading simultaneously.

Second, by delivering power to the transmission and distribution grid in the western part of the GTA, an area experiencing rapid growth in electricity demand, Lakeview GS plays a unique and critical role. During peak demand periods, the output from Lakeview GS is not only essential to meet the demands of customers in Etobicoke, Mississauga and Oakville, but also helps ensure a reliable electricity supply across the province by providing voltage regulation, thereby minimizing the risk of low voltage brownouts or supply interruptions. This service is especially important during periods of heavy air conditioning loads typically associated with the hot humid weather that often leads to smog episodes.

On only two occasions this summer have we had AQI forecast of "poor" (June 10 and July 1). These were both Saturdays, and only two units are available on weekends at Lennox. On June 10, two units operated at Lennox and one unit at 200 MW at Lakeview. On July 1, one unit ran at Lennox and none at Lakeview.

In your second letter, you seek assurance on your calculations that if OPG eliminated export sales on smog alert days, the impact on the Ontario consumer would be 4 cents per customer per year. It is not possible to make a simple correlation between customer impact and export sales. Ontario Hydro/Ontario Power Generation has been operating under a rate freeze since 1993. It is also worthwhile to note Ontario Power Generation has been a net importer of electricity since shutting down seven nuclear units in 1997/98. The inter-ties with the US were established to ensure reliability of electricity within Canada and the US, and to do so in an economic fashion. Generally speaking, we import power during winter and export in the summer.

If you would like to discuss further, or perhaps would like a tour of Lakeview to get a feel for how it operates, please give me a call.

Thank you for your interest in Ontario Power Generation's AQI initiative.

J.R. Burpee

ONTARIO POWER GENERATION

700 University Avenue
Toronto, Ontario
M5G 1X6

Angelo G. Castellan
Director, Environment Division
Electricity Production
Phone: (416) 592-5409 Facsimile: (416) 592-4841 Location: H15 A1
Email: angelo.castellan@ontariopowergeneration.com

May 15, 2001

Mr. Jack Gibbons
Chair
Ontario Clean Air Alliance
625 Church Street, Suite 402
Toronto, Ontario
M4Y 2G1

Dear Sir:

In reply to your letter to our President and CEO (April 24, 2001), I would like to advise that OPG will continue its voluntary practise of committing Lennox units ahead of the Lakeview units for the summer of 2001, under conditions when the "tomorrow" air quality index (AQI) forecast for Toronto or Halton-Peel is poor. For these AQI alert days, Lennox will be dispatched ahead of Lakeview in order to meet primary demand, obligatory reserve requirements, previously committed sales, emergency sales, and spot market sales.

Export markets are complex in nature, and can include long-term contracts, spot market opportunities, and system reliability considerations. It is worthwhile to note that OPG has been a net importer of electricity since shutting down the nuclear units in 1997/8. The inter-ties with the U.S. were established to ensure reliability of electricity within Canada and the U.S., and to do so in an economic fashion.

At OPG, we continue to invest in, and operate our coal plants to make them among the cleanest in our air shed. You are no doubt aware of our quarter billion dollar investment over 2002 and 2003 in four selective catalytic reduction units at the Nanticoke and Lambton stations, that will further reduce nitrogen oxide emissions by 80 per cent on the 4 of our 12 major coal-fueled units where they are installed, and representing a system-wide reduction of about 25 per cent. We will also complete the installation of low nitrogen oxide (NOx) burners at our Lakeview Generating Station before this summer's smog season. This will result in a 50 per cent decrease in the NOx emission rates from that plant over the past two years.

Given the excellent performance of our "fleet" atmospheric emissions compared to our American neighbours in the same air shed and market place, and the environmental improvements that we continue to make at our fossil-fired generating plants, we plan to continue to participate in these regions as opportunities arise.

A. Castellan

A.G. Castellan

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Faxed Mar-28/02

ONTARIO POWER GENERATION

Graham A. Brow
Chief Operating Offi

700 University Avenue, Toronto, Ontario M5G 1X6

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graham.brown@opg.c

March 28th, 2002

Mr. Jack Gibbons
625 Church Street, Suite 402
Toronto, ON
M4Y 2G1

Dear Jack,

OPERATION OF LAKEVIEW GENERATING STATION DURING SMOG ADVISORIES

Thank you for your letter of 22 February. As you are aware, we are actively negotiating the sale of both Lakeview and Lennox generating stations. One or both of these plants may well be in third party hands by the summer and we have no power to bind the way in which the new owners of these plants will compete in the future.

In any event, once the market opens on 1 May this year, plant dispatch becomes the responsibility of the Independent Electricity Market Operator ("IEMO"). OPG will have no remit in determining which plants are called to run.

However, OPG remains keen to maintain its voluntary stance of previous years to the extent it can. In the event Lakeview remains under OPG control this summer, OPG will, during periods where a smog advisory is in force, seek to offer Lakeview for dispatch is a way that results in it running after Lennox, as it has done during advisories in previous years.

Yours sincerely,

Graham

Graham Brown

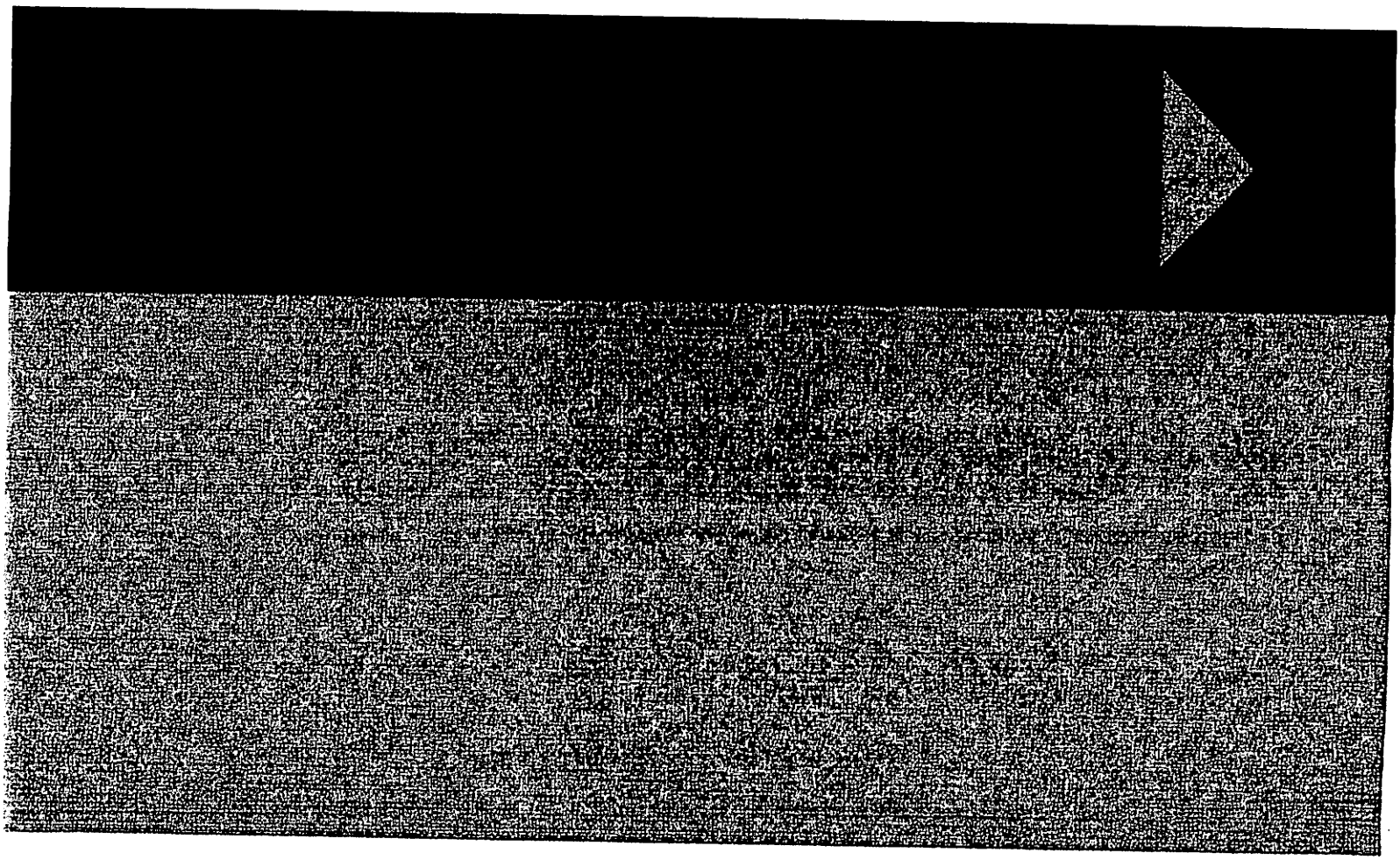
Treasury Board of Canada Secretariat
Secrétariat du Conseil du Trésor du Canada

Interim

37

Canadian Cost-Benefit Analysis Guide

Regulatory Proposals



Canada

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This document is also available in alternative formats on request.

4.7 Discount rates

For each option under consideration, the stream of costs and benefits will usually not occur in the same year but is spread over several years. Discounting allows for the systematic comparison of costs and benefits that occur in different time periods by allowing one to calculate the net present value of the intervention. If the costs and benefits are expressed in current prices or nominal dollars, they should be deflated to become real prices or prices expressed in terms of the price level of a specific year. In this way, the changes in the reported values of benefits and costs over time that are due purely to inflation are removed.

The discounted present value of net benefits is the algebraic sum of the present values of the expected incremental net benefits of the policy option over and above the baseline scenario during the policy's anticipated impact time period. If the net present value (NPV) is greater than or equal to zero, then the policy is expected to generate more benefits than costs and should be recommended for implementation. However, if the NPV is less than zero, the policy should not be recommended for implementation on efficiency grounds.

4.7.1 Rational approaches to discount rates

Choosing a discount rate has been one of the most contentious and controversial aspects of the cost-benefit analysis of regulatory policies. The term *discount rate* refers to the time value of the costs and benefits from the viewpoint of society. It is similar to the concept of the private opportunity cost of capital used to discount a stream of net cash flows of an investment project, but the implications can be more complex.

With costs and benefits expressed in real values, people prefer to make payments later and receive benefits sooner. This is due to the fact there is a time preference for current consumption over future consumption. Similarly, there is an opportunity cost of the resources invested in any given activity, as they could have been invested elsewhere if they had not been spent on the activity being evaluated.

One approach to discounting is based on the fact that present consumption is valued differently from future consumption. Following this approach, all benefits and costs are first converted into quantities of consumption equivalents before being discounted. In this case, the discount rate is the rate of time preference at which individuals are willing to exchange consumption over time.

Another approach considers what society forgoes in terms of pre-tax returns of displaced investment in the country. Using this approach, no account is made for time preference in terms of present versus future consumption. The discount rate is based purely on the opportunity cost of forgone investments.

An approach that captures the essential features of both these two alternatives uses a weighted average of the economic rate of return on private investment and the time preference rate for

consumption.[33] Many professionals have chosen to use a discount rate that follows this weighted average opportunity cost of funds concept.

A natural place to look for the relative weights to place on the rate of time preference and the gross rate of return on investment is the response of the capital market to extractions or injections of funds. On the cost side, the marginal source of funds for both the public and private sectors is usually from borrowing either domestically or from abroad. Likewise, if benefits arise that create income, it will be in the first instance deposited in financial institutions, where it is available to finance other activities.

While this approach is not without its restrictions, these pale in comparison to the practical problems that arise if the rate of time preference is used as the rate of discount for such interventions.[34]

Other questions have been raised as to whether a lower rate should be used for intergenerational discounting because many of the people affected by some policy or regulation may no longer be alive in the distant future. However, there is little consensus in the literature on discounting for intergenerational policies. There are several reasons for not favouring the use of variable discount rates in the analysis. First, no genuine rationale can be found for use of different discount rates over the policy impact period, unless the opportunity cost of funds is abnormally high or low from one period to another. Second, applying one discount rate to the streams of costs and another to the streams of benefits can be tricky and empirically difficult for each policy because of the requirements for converting all the streams of costs into consumption equivalents in a consistent manner.

Moreover, a risk-adjusted discount rate has also been suggested elsewhere to account for the systematic risk of future uncertainty. Since the streams of uncertain future costs and benefits are mainly related to the input variables themselves, they are best dealt with in the Monte Carlo risk analysis rather than the adjusted discount rates.

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33. See e.g. Agnar, Sandmo and Jacques H. Dreze, "Discount Rates for Public Investment in Closed and Open Economics." In: *Economica*, November 1971; Harberger, Arnold C., "On Measuring the Social Opportunity Cost of Public Funds." In: Arnold C. Harberger, ed., *Project Evaluation—Collected Papers*, Chicago: University of Chicago Press, 1972.

34. For an extensive theoretical discussion of these alternative methods of economic discounting, see Sjaastad, Larry A. and Daniel L. Wisecarver, "The Social Cost of Public Finance." In: *The Journal of Political Economy*, Vol. 85, No. 3, June 1977.

4.7.2 Discount rates

When a program requires funds that are extracted from the capital markets, the funds are drawn from three sources. First, funds that would have been invested in other investment activities have now been displaced by expenditures required by the policy action. The cost of these funds is the return that would have been earned on the alternative investments. Second, funds come from different categories of savers in the country who postpone their consumption in the expectation of getting a return on their savings. The cost of this part of the funds is reflected in the interest rate that the savers earn net of personal income tax. Third, some funds may come from abroad, that is from foreign savers. The cost of these funds would be the marginal cost of foreign borrowing. At the margin, the cost associated with incremental foreign borrowing is measured by the interest expense on the incremental borrowings plus the marginal change in the cost of foreign borrowing times the quantity of the stock of foreign debt negotiated at variable interest rates.

The discount rate will be a weighted average of the costs of funds from the three sources outlined above: the rate of return on postponed investment, the rate of interest (net of tax) on domestic savings, and the marginal cost of additional foreign capital inflows. The weights are equal to the proportion of funds sourced from domestic private-sector investors, domestic private-sector savers, and foreign savers.

Based on the above approach, the discount rate for Canada was re-estimated recently by Jenkins and Kuo (2007). It is found to be a real rate of approximately 8 per cent.[35] This rate is lower than the real rate of discount of 10 per cent recommended by the Treasury Board of Canada Secretariat in 1998 but is higher than the 7 per cent real rate proposed by Burgess in 1981 and the 7.3 per cent real rate recommended by Brean et al.[36] This rate of 8 per cent is consistent with the 10 per cent estimated earlier and used in the Treasury Board guidelines of 1976 and 1998.[37] Over time, the effective rate of corporate income tax in Canada has been steadily decreasing. Furthermore, the introduction of the goods and services tax has removed much of the burden of the sales tax system from the value added of capital. Both these policy changes will tend to lower the required gross of tax rate of return on capital. We recommend that a real rate of 8 per cent be used as the discount rate for the evaluation of regulatory interventions in Canada.

In certain circumstances where consumer consumption is involved and there are no or minimal resources involving opportunity costs (such as certain human health and environmental goods and services), some federal departments, governments, and international organizations have taken into consideration factors other than the economic opportunity cost of funds when developing their recommendations for the value of the discount rate. Usually these social

35. Jenkins, Glenn and Chun-Yan Kuo, "The Economic Opportunity Cost of Capital for Canada—An Empirical update," QED Working Paper Number 1133, Department of Economics, Queen's University, Kingston, Canada, 2007.
36. See e.g. Burgess, David F., "The Social Discount Rate for Canada: Theory and Evidence." In: *Canadian Public Policy*, Summer 1981; Jenkins, Glenn P., "The Public-Sector Discount Rate for Canada: Some Further Observations." In: *Canadian Public Policy*, Summer 1981; Brean, Donald, David Burgess, Ronald Hirshhorn, and Joseph Schulman, *Treatment of Private and Public Charges for Capital in a "Full-Cost Accounting" of Transportation: Final Report*, March 2005.
37. Jenkins, Glenn P., "Measurement of Rates of Return and Taxation from Private Capital in Canada." In: W. A. Niskanen et al., eds., Benefit-Costs Analysis, Chicago: Aldine, 1972.

discount rates are lower than the 8 per cent recommended here. One approach is to estimate the social time preference rate, which is based on the rate at which individuals discount future consumption and projected growth rate in consumption.[38] For Canada, the social time preference rate has been estimated to be around 3 per cent.[39] In these circumstances, the net present value of the results of the analysis can also be carried out using a social discount rate of 3 per cent accompanied by the use of a shadow price of investment that is applied to all the costs of the intervention that results in a postponement or reduction of investment activity. However, there is still controversy in the literature on the use of these social discount rates and further guidance will be needed in the future. Whatever rate is used, the costs and benefits should be discounted using the same rate.

The government has established the Centre of Regulatory Expertise that for a period of five years will help departments and agencies adjust to the new approach to regulating, including cost-benefit analysis, instrument choice, and performance measurement. This assistance will include the provision of specialist analytical services. Departments and agencies are expected to discuss their approach to cost-benefit analysis with their Treasury Board of Canada Secretariat analyst, including the need for and approach to discounting any longer-term costs and benefits associated with proposals involving, for example, health and environmental regulation.

4.7.3 Annualized costs and benefits

Cost-benefit analysis results should also be presented in terms of annualized values. This is especially the case when alternative policies have different time horizons. Comparing the net present value between two policies will not be valid unless further adjustments are made.[40] However, once net benefits are annualized to become constant annual values, comparing annualized net benefits is equivalent to comparing the net present values of net benefits with further adjustments.

To annualize the net benefits of a policy, the following relationship holds between the present value of net benefits over the n policy impact periods and its annualized value:[41]

$$AV = [PV \cdot \rho]/[1 - (1+\rho)^{-n}]$$

where AV is the annualized value of net benefits over the n periods;

PV is the present value of net benefits over the n periods;

ρ is the economic discount rate; and

n is the duration of the policy impact periods.

38. Policy Research Initiative, *Social Discount Rates for Canada*, Ottawa, 2007.
39. Ibid.
40. One can adjust the costs and benefits of alternative options to the same length of periods. See e.g. Harberger, Arnold C. and Jenkins, Glenn P., *Manual on Cost-Benefit Analysis for Investment Decisions*, Queen's University, Kingston, Canada, 2002.
41. The formula can be found in the European Commission, *Impact Assessment Guidelines*, June 15, 2005.

This approach allows us to express and compare net benefits that occur in different policy impact time periods on a consistent basis. Annualization simply spreads the net benefits smoothly through time. An example is given below.

Annualization of Net Benefits

Suppose there are two mutually exclusive projects. Project A generates a present value of net benefits of $1,500 million over a five-year period. Project B generates a present value of net benefits of $1,700 million over a seven-year period. With the simple net present value criteria, Project B would be recommended. However, we have problems with a longer time horizon than that of Project A.

- We can calculate the annualized value of the net benefits as follows:

  For Project A, the annualized value of the benefits is:

  $AV_A = [1,500 \times 0.08 / (1 - (1 + 0.08)^{-5}] = \$375.7$ million

  For Project B, the annualized value of the benefits is:

  $AV_B = [1,750 \times 0.08 / (1 - (1 + 0.08)^{-7}] = \$336.1$ million

- Conclusion: The higher present value of the net benefits for Project B than for Project A is due to a longer time horizon. When the value of net benefits is normalized with respect to time period, it is shown that Project A is in fact preferred.

STEP 5: Preparing an Accounting Statement

After completing the analysis, it is expected that the results will be summarized in an accounting statement. Analysts are advised to adopt the format that is best suited for a specific policy, while remaining faithful to the intent of the accounting statement, as illustrated below. The purpose is to highlight key components of the benefits and costs associated with the policy and the total net outcome of the analysis.

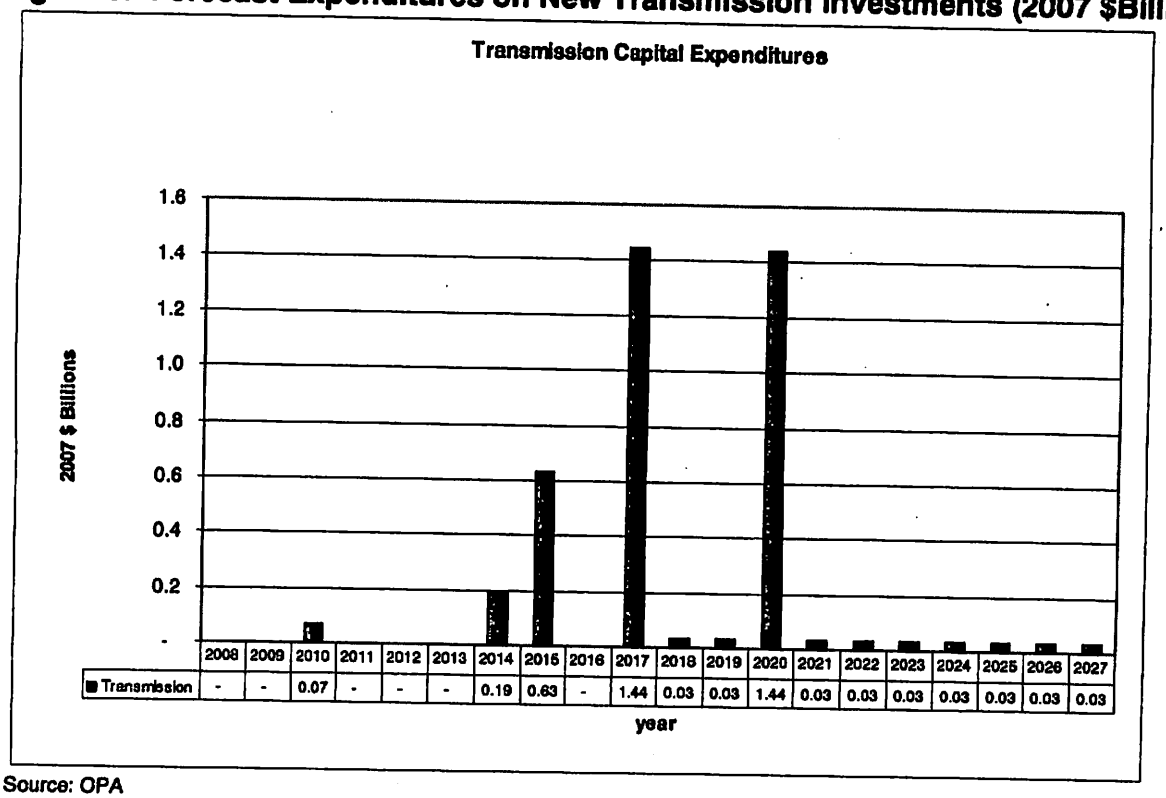
5.1 Cost-benefit analysis for each option (accounting statement section A)

Table 1 provides the incremental benefits and costs of the policy as compared to the baseline scenario. For each option, two sets of analytical results can be shown. Part I presents the results of benefits and costs based on single (deterministic) values for all of the variables affecting the policy outcome, where no risk or uncertainty is assumed for the values. Part II presents Monte Carlo simulation results by dealing with uncertainty and risk surrounding the future value each of the key input variables contributes to the policy outcome.

In the deterministic case, one should present not only annual estimates of benefits and costs but also the present value or annualized value of the net benefits over the policy impact period. This is shown in Part IA of Table 1.

Annual estimates of the undiscounted streams of benefits and costs should be presented over the impacted period. The impacted period could vary from one policy to another and a time interval could also be used if more relevant. If the original estimates are expressed in nominal dollars, they should be deflated to become real prices or prices expressed in terms of the price level of a

Figure 6: Forecast Expenditures on New Transmission Investments (2007 $Billions)



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Transmission	-	-	0.07	-	-	-	0.19	0.63	-	1.44	0.03	0.03	1.44	0.03	0.03	0.03	0.03	0.03	0.03	0.03

Source: OPA

Q. What assumptions were used to develop the Plan cost?

A. The assumptions used to derive these costs are set out in Table 1 which shows the capital and operating cost assumptions of planned generation.

Table 1: Cost Assumptions for Planned Generation

GENERATION TYPE	Capital Cost $/kw	Construction Period (years)	Fixed O&M $/kw	Variable O&M $/MWh	Heat Rate	Operating Life
CCGT	924	3	17.0	2.7	7,000	20
SCGT	665	2	16.0	3.5	9,500	20
Biogas	2,096	2	231.0	27.0	10,000	20
Cogen	1,413	3	22.0	2.7	6,300	20
Hydro RR	3,570	4	41.8	0.0		50
Hydro DIS	2,550	4	41.8	0.0		50
Nuclear	2,907	6	108.1	3.1	10,500	40
Wind	1,938	1	47.9	0.0		20
NUG replacing CCGT	924	3	17.0	2.7	7,000	10
Fuel Cell	5,447	3	8.3	54.1	7,930	20
Solar	5,712	2	13.3	0.0	10,280	20
Nuclear Refurbishment Cost $M per unit	1,514					

Source: OPA

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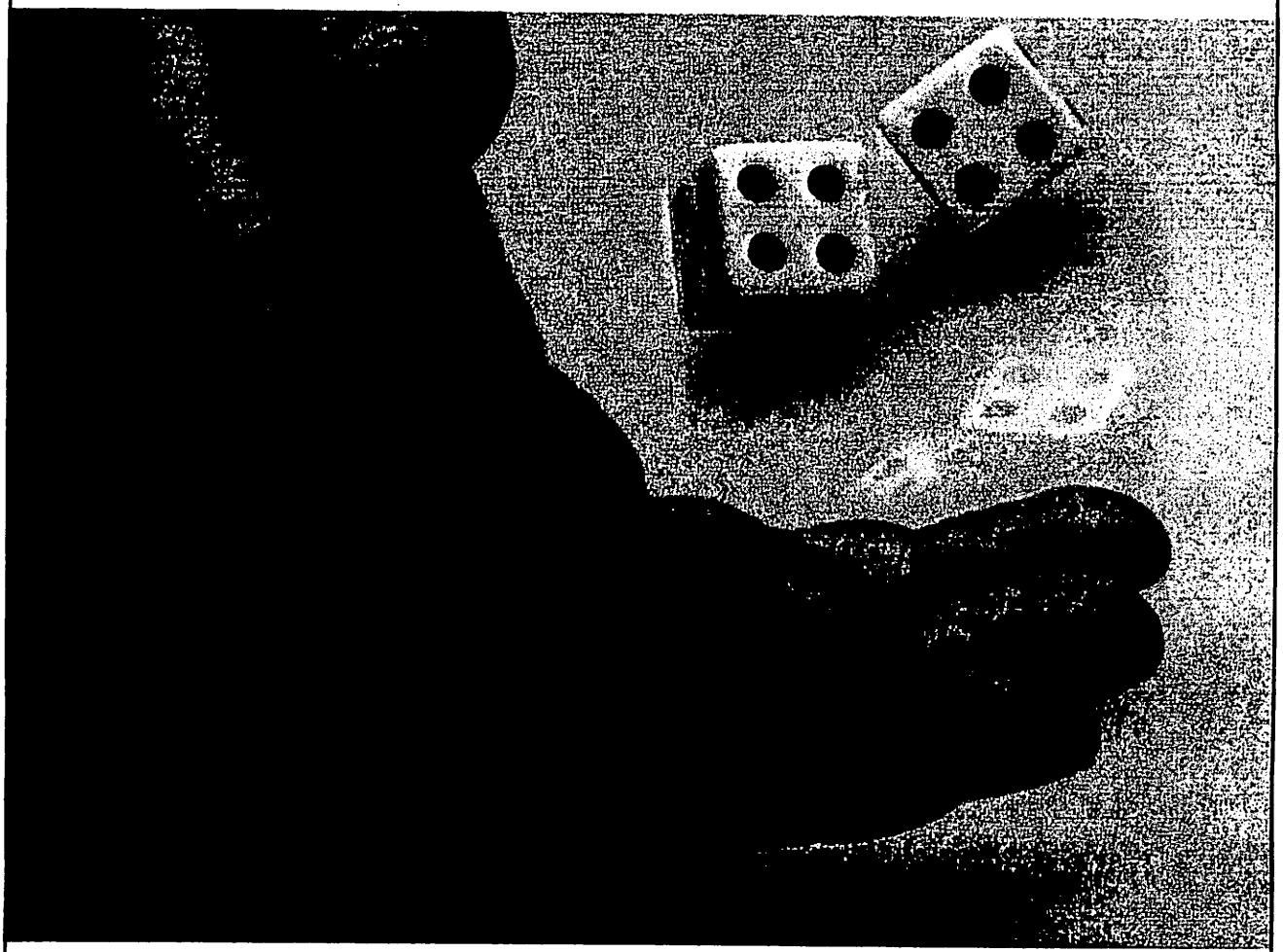
Rolling the Dice:



A Review of the Ontario Power Authority's High-Risk Strategy to Meet Our Electricity Needs

Ontario Clean Air Alliance

FEBRUARY 9, 2007

Optimistic Nuclear Assumptions

Nuclear Capital Costs

The OPA's analysis assumes that the capital cost of a new CANDU 6 nuclear reactor, $2,845/kW (2005 $),[17] will be 30% *less* than the actual historic capital cost, $4,085/kW (1993 $), of the last nuclear power plant, the Darlington Nuclear Station, built in Ontario.[18]

Actual Ontario Nuclear Capital Costs Are Always Greater Than Forecast

The OPA's assumption that the cost per kW of a new nuclear reactor will be 30% less than the actual historic cost of Darlington is very problematic for at least two reasons. First, in general, inflation has raised prices by 25% since 1993.[19] Second, in Ontario, the actual capital cost of building or retrofitting nuclear reactors has always been much greater than forecast.

- In 1983, Ontario Hydro estimated that the total capital cost of Darlington would be $4 billion. Its actual total cost was 3.6 times greater, at $14.3 billion.[20]
- In 1999, Ontario Power Generation (OPG) estimated that the total cost of returning Pickering A Unit 4 to service would be $457 million. Its actual cost was 2.7 times greater, at $1.25 billion.[21]
- In 1999, OPG estimated that the total cost of returning Pickering A Unit 1 to service would be $213 million. Its actual cost was 4.8 times greater at $1.016 billion.[22]
- Bruce Power estimated that the total cost of returning Bruce A Units 3 and 4 to service would be $375 million.[23] Its actual cost was 2 times greater, at $750 million.[24]

Financing Costs

The OPA's analysis assumes that the required real pre-tax rate of return on capital for a new nuclear power plant would be between 5% and 11%.[25] However, according to CIBC World Markets, Bruce Power's (Canada's only investor-owned nuclear power company) actual cost of capital is 30 to 70% higher than the highest required rate of return on capital (a real pre-tax rate of 11%) used by the OPA.[26]

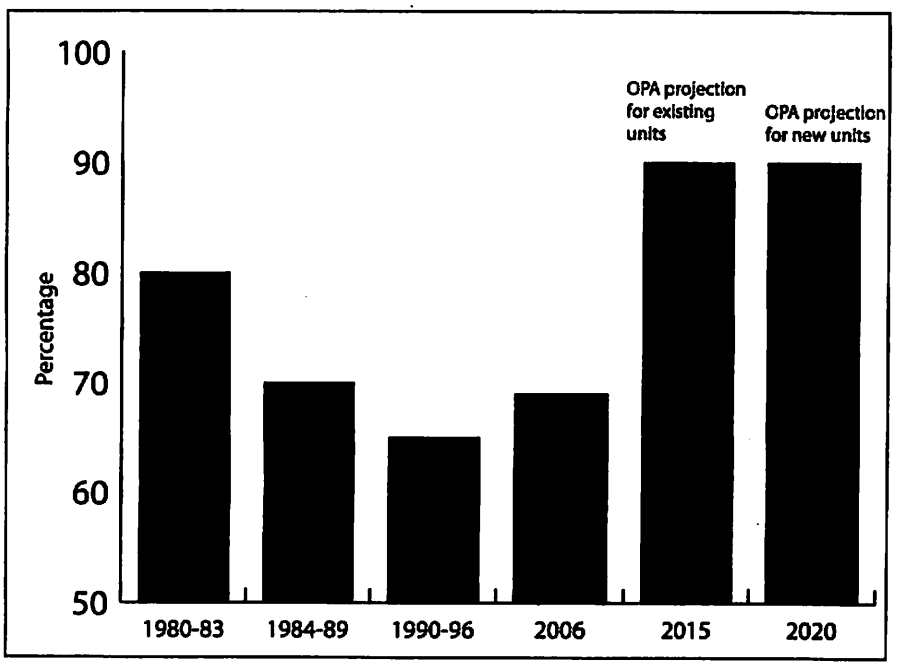
Annual Capacity Utilization Rates

The OPA's analysis assumes that the annual capacity utilization rates of our existing and new nuclear reactors in Ontario will be 90% in 2015 and 2020 respectively.[27] However, during the last 25 years the average capacity utilization rate of Ontario's fleet of nuclear reactors has never equaled 90%.

According to the Government of Ontario, the actual capacity utilization rate of Ontario's fleet of nuclear reactors declined from 80% between 1980 and 1983; to 70% between 1984 and 1989; and then to 65% between 1990 and 1996.[28] In 2006 the average capacity utilization rate of Ontario's fleet of nuclear reactors was 69%.[29]

As a result of the declining capacity utilization rates of Ontario's nuclear fleet, OPG had to increase the output of its coal-fired power plants by 117% between 1995 and 2003 to keep the lights on.[30] If Ontario's existing nuclear units are unable to achieve a 90% annual capacity utilization rate in 2015, will the OPA recommend that we continue to operate our coal-fired power plants to keep the lights on?

Fig. 6: Nuclear capacity utilization rates — actual and OPA projected

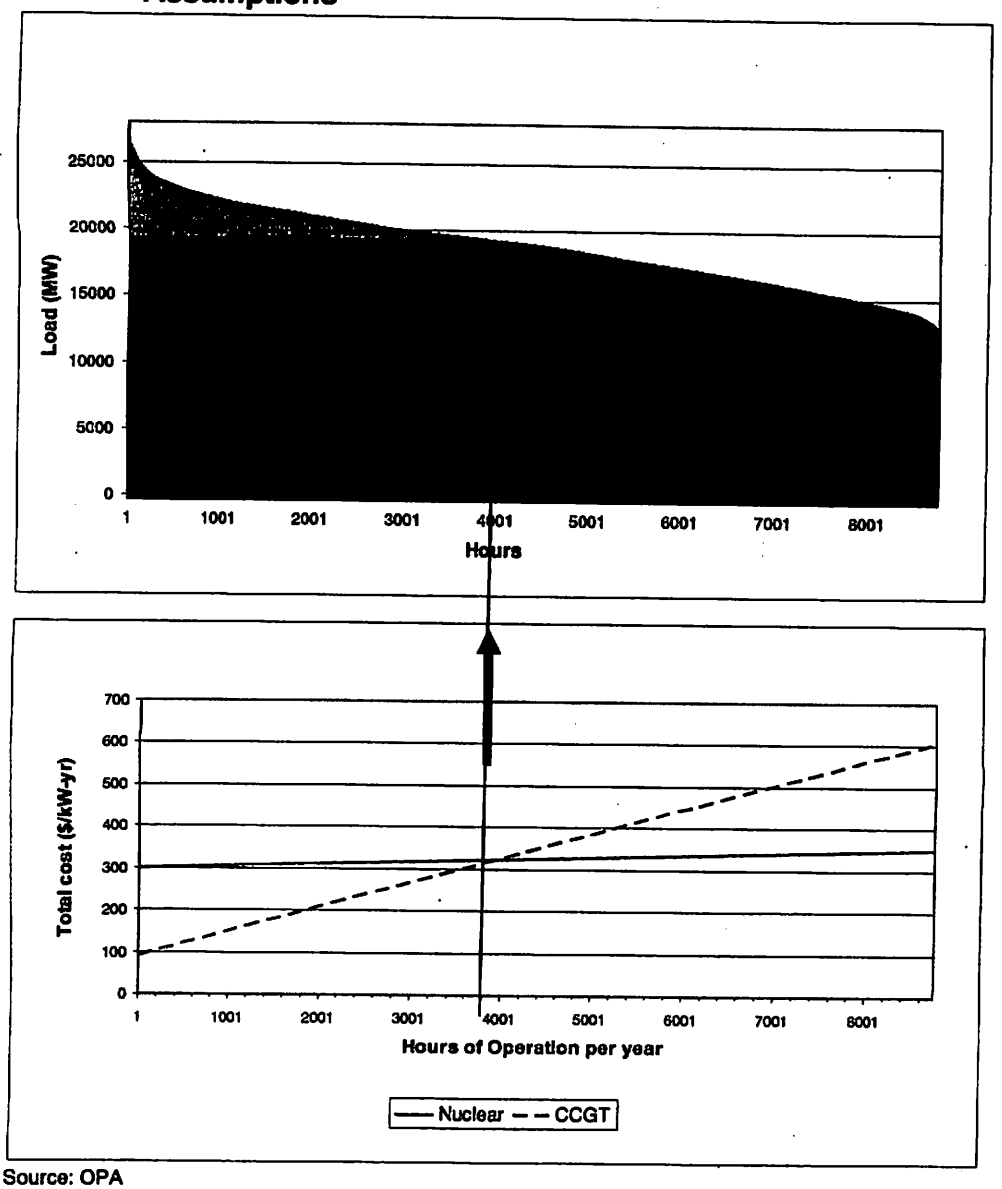


Reliability

As a result of Ontario's heavy dependency on CANDU nuclear reactors, it took Ontario more than 8 days to fully recover from the August 14, 2003 blackout versus less than 2 days for New York State.[31]

utilization rates to the load duration curve for the system (since electricity cannot be stored)"

Figure 3: Baseload Generation Requirement (19,000 MW) in 2015 under Deterministic Assumptions



Source: OPA

Excerpts from the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Sched. B[1]

Board objectives, electricity

1. (1) The Board, in carrying out its responsibilities under this or any other Act in relation to electricity, shall be guided by the following objectives:

1. To protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service.

2. To promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry. 2004, c. 23, Sched. B, s. 1.

Facilitation of integrated power system plans

(2) In exercising its powers and performing its duties under this or any other Act in relation to electricity, the Board shall facilitate the implementation of all integrated power system plans approved under the *Electricity Act, 1998*. 2004, c. 23, Sched. B, s. 1.

[1] Taken from Ontario's E-Laws website on January 14, 2008.

Excerpts from the *Electricity Act, 1998*, S.O. 1998, c. 15, Sched. A[1]

Integrated power system plan

25.30 (1) Once during each period prescribed by the regulations, or more frequently if required by the Minister or the Board, the OPA shall develop and submit to the Board an integrated power system plan,

(a) that is designed to assist, through effective management of electricity supply, transmission, capacity and demand, the achievement by the Government of Ontario of,

(i) its goals relating to the adequacy and reliability of electricity supply, including electricity supply from alternative energy sources and renewable energy sources, and

(ii) its goals relating to demand management; and

(b) that encompasses such other related matters as may be prescribed by the regulations. 2004, c. 23, Sched. A, s. 34.

Minister's directives

(2) The Minister may issue, and the OPA shall follow in preparing its integrated power system plans, directives that have been approved by the Lieutenant Governor in Council that set out the goals to be achieved during the period to be covered by an integrated power system plan, including goals relating to,

(a) the production of electricity from particular combinations of energy sources and generation technologies;

(b) increases in generation capacity from alternative energy sources, renewable energy sources or other energy sources;

(c) the phasing-out of coal-fired generation facilities; and

(d) the development and implementation of conservation measures, programs and targets on a system-wide basis or in particular service areas. 2004, c. 23, Sched. A, s. 34.

Publication

(3) A directive issued under subsection (2) shall be published in *The Ontario Gazette*. 2004, c. 23, Sched. A, s. 34.

Review of integrated power system plan

(4) The Board shall review each integrated power system plan submitted by the OPA to ensure it complies with any directions issued by the Minister and is economically prudent and cost effective. 2004, c. 23, Sched. A, s. 34.

Board's powers

(5) After review, the Board may approve a plan or refer it back with comments to the OPA for further consideration and resubmission to the Board. 2004, c. 23, Sched. A, s. 34.

[1] Taken from Ontario's E-Laws website on January 14, 2008.

Deadline for review
(6) The Board shall carry out the review of an integrated power system plan under subsection (4) within such time as the Minister directs. 2004, c. 23, Sched. A, s. 34.

Procurement process for electricity supply, etc.
25.31 (1) The OPA shall develop appropriate procurement processes for managing electricity supply, capacity and demand in accordance with its approved integrated power system plans. 2004, c. 23, Sched. A, s. 35.

Same
(2) The OPA's procurement processes must provide for simpler procurement processes for electricity supply or capacity to be generated using alternative energy sources or renewable energy sources, or both, where the supply or capacity or the generation facility or unit satisfies the prescribed conditions. 2004, c. 23, Sched. A, s. 35.

Application for approval
(3) The OPA shall apply to the Board for approval of its proposed procurement processes, and any amendments it proposes. 2004, c. 23, Sched. A, s. 35.

Board approval
(4) The Board shall review the OPA's proposed procurement processes and any proposed amendments and may approve the procurement processes or refer all or part of them back with comments to the OPA for further consideration and resubmission to the Board. 2004, c. 23, Sched. A, s. 35.

Deadline for review
(5) The Board shall carry out the review of the proposed procurement processes and any proposed amendments within such time as the Minister directs. 2004, c. 23, Sched. A, s. 35.

Procurement contracts
25.32 (1) When the OPA considers it advisable, it shall enter into contracts in accordance with procurement processes approved under section 25.31 for the procurement of,

(a) electricity supply or capacity, including supply or capacity to be generated using alternative energy sources, renewable energy sources or both; or
(b) measures that will manage electricity demand or result in the improved management of electricity demand on an on-going or emergency basis. 2004, c. 23, Sched. A, s. 36.

Contract to comply with regulations
(2) The OPA shall not enter into a procurement contract that does not comply with the regulations. 2004, c. 23, Sched. A, s. 36.

Resolution of procurement contract disputes
(3) The parties to a procurement contract shall ensure that the contract provides a mechanism to resolve any disputes between them with respect to the contract. 2004, c. 23, Sched. A, s. 36.

Transition
(4) Despite subsection (2), the Minister may direct the OPA to assume, as of such date as the Minister considers appropriate, responsibility for exercising all powers and performing all duties of the Crown, including powers and duties to be exercised and performed through an agency of the Crown,

(a) under any request for proposals, draft request for proposals, another form of procurement solicitation issued by the Crown or through an agency of the Crown or any other initiative pursued by the Crown or through an agency of the Crown,
  (i) that was issued or pursued after January 1, 2004 and before the Board's first approval of the OPA's procurement process under subsection 25.31 (4), and
  (ii) that relates to the procurement of electricity supply or capacity or reductions in electricity demand or to measures for the management of electricity demand; and

(b) under any contract entered into by the Crown or an agency of the Crown pursuant to a procurement solicitation or other initiative referred to in clause (a). 2004, c. 23, Sched. A, s. 36.

Release of the Crown, etc.
(5) As of the day specified in the Minister's direction under subsection (4), the OPA shall assume responsibility in accordance with that subsection and the Crown and any Crown agency referred to in that subsection are released from any and all liabilities and obligations with respect to the matters for which the OPA has assumed responsibility. 2004, c. 23, Sched. A, s. 36.

Deemed compliance
(6) The following contracts shall be deemed to be procurement contracts entered into in accordance with any integrated power system plan and procurement process approved by the Board:

1. A contract entered into by the OPA following a procurement solicitation or other initiative referred to in clause (4) (a).
2. A contract referred to in clause (4) (b). 2004, c. 23, Sched. A, s. 36.

Same
(7) The OPA shall enter into any contract following a procurement solicitation or other initiative referred to in clause (4) (a) if directed to do so by the Minister of Energy, and that contract shall be deemed to be a procurement contract that was entered into in accordance with any integrated power system plan and procurement process approved by the Board. 2004, c. 23, Sched. A, s. 36.

Amendment of market rules

33. (1) The IESO shall, in accordance with the market rules, publish any amendment to the market rules at least 22 days before the amendment comes into force. 2004, c. 23, Sched. A, s. 42.

Notice to the Board

(2) The IESO shall give the Board a copy of the amendment and such other information as is prescribed by the regulations on or before the date the IESO publishes the amendment under subsection (1). 2004, c. 23, Sched. A, s. 42.

Board's power to revoke

(3) Despite section 4.1 of the Statutory Powers Procedure Act and section 35.1 of this Act, the Board may, not later than 15 days after the amendment is published under subsection (1) and without holding a hearing, revoke the amendment on a date specified by the Board and refer the amendment back to the IESO for further consideration. 2004, c. 23, Sched. A, s. 42.

Application for review

(4) Any person may apply to the Board for review of an amendment to the market rules by filing an application with the Board within 21 days after the amendment is published under subsection (1). 2004, c. 23, Sched. A, s. 42.

Application of Ontario Energy Board Act, 1998

(5) Subsection 19 (4) of the Ontario Energy Board Act, 1998 applies to an application under subsection (4). 2004, c. 23, Sched. A, s. 42.

Review by Board

(6) The Board shall issue an order that embodies its final decision within 60 days after receiving an application for review of an amendment. 2004, c. 23, Sched. A, s. 42.

Stay of amendment

(7) No application for review of an amendment under this section shall stay the operation of the amendment pending the completion of the Board's review of the amendment unless the Board orders otherwise. 2004, c. 23, Sched. A, s. 42.

Same

(8) In determining whether to stay the operation of an amendment, the Board shall consider,

(a) the public interest;
(b) the merits of the application;
(c) the possibility of irreparable harm to any person;
(d) the impact on consumers; and
(e) the balance of convenience. 2004, c. 23, Sched. A, s. 42.

Order

(9) If, on completion of its review, the Board finds that the amendment is inconsistent with the purposes of this Act or unjustly discriminates against or in favour of a market participant or class of market participants, the Board shall make an order,

(a) revoking the amendment on a date specified by the Board; and

(b) referring the amendment back to the IESO for further consideration. 2004, c. 23, Sched. A, s. 42.

EB-2007-0707
Exhibit A
Tab 3
Schedeule 1
Page 1 of 48

Ontario Energy Board

Report of the Board on the Review of, and Filing Guidelines Applicable to, the Ontario Power Authority's Integrated Power System Plan and Procurement Processes

December 27, 2006

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Under the *Electricity Act, 1998* (the "Act"), the Ontario Power Authority (the "OPA") is responsible for developing both an integrated power system plan (the "IPSP") and adequate procurement processes for managing electricity supply, capacity and demand in accordance with the IPSP. The OPA's IPSP and procurement processes must both be submitted to the Ontario Energy Board (the "Board") for review and approval. It is expected that the OPA will file the IPSP and its procurement processes concurrently.

This Report has been prepared to provide guidance in relation to the approach to be used by the Board in reviewing the IPSP and the OPA's procurement processes, as well as in relation to the Board's expectations regarding the OPA's filings. It is divided into two Parts. Part One deals with the review of the IPSP and is divided into three sections. The first section provides an overview of the legislative framework for, and the Ministerial directive applicable to, the IPSP. The second section describes principles that the Board will use to guide its review of the IPSP. The third section contains guidelines for the OPA's filing in relation to the IPSP. Part Two deals with the review of the OPA's procurement processes. It provides an overview of the legislative framework applicable to the OPA's procurement processes, the principles that the Board will use to guide its review of those processes, and the elements that the Board expects to be addressed by the OPA in relation to different types of procurement processes.

Development of this Report has been informed by consultation with interested parties, including the OPA. That consultation has confirmed that different parties have, on a number of issues, quite different expectations. This is to be anticipated, since the development and approval of an IPSP, as well as of the OPA's procurement processes, are new activities for each of the OPA and the Board.

The IPSP and the OPA's procurement processes will be the subject of a hearing before a panel of the Board. This Report is not intended to confine the discretion of that panel in hearing and determining the matter, but rather to provide some structure around the exercise of that discretion. The principles set out in Part One are those that the Board considers should, as a matter of policy and interpretation of the Board's mandate, inform the panel's overall approach. The filing guidelines set out in Part Two reflect the Board's current view as to the information that may be required in order for the Board to fulfill its statutory mandate. The Board recognizes that, while there is merit in providing guidance in this regard, there is also a need to maintain some degree of flexibility. The OPA is responsible for making its case for approval of the IPSP and its procurement processes to the satisfaction of the Board. It retains the right to do so in the manner it considers most appropriate.

PART ONE: THE IPSP

I. Introduction

A. Overview of the IPSP

As described in section 25.30(1) of the Act, the IPSP is a plan "to assist, through the effective management of electricity supply, transmission, capacity and demand," the achievement by the Government of Ontario of certain goals and to encompass other matters prescribed in regulations. The goals relate specifically to the adequacy and reliability of electricity supply, including electricity supply from alternative energy sources and renewable energy sources, and to demand management.

In developing the IPSP, the OPA must follow directives issued to the OPA by the Minister of Energy in relation to the IPSP (the "IPSP Directives") and is required to comply with the *Integrated Power System Plan Regulation*, O. Reg. 424/04 (the "IPSP Regulation"). IPSP Directives set out the goals to be achieved during the period covered by the IPSP. The IPSP Regulation sets out matters that the OPA is required to (i) identify, (ii) identify and develop, or (iii) consider in preparing the IPSP, as well as matters that must be included in the IPSP.

The IPSP Regulation also requires that the IPSP cover a period of twenty years, and that it be updated and submitted to the Board for approval every three years. The Minister or the Board may require more frequent updates.

Appendix A contains excerpts from the Act that relate to the IPSP, as well as the provisions of the IPSP Regulation.

B. IPSP Directives

IPSP Directives are an articulation of the Government's policy goals for the IPSP and are binding on the OPA.

On June 13, 2006, the Minister of Energy provided direction to the OPA in relation to the preparation of the IPSP (the "Supply Mix Directive"). At the time of preparation of this Discussion Paper, the Supply Mix Directive was the sole IPSP Directive issued by the Minister.

The Supply Mix Directive is discussed further in section II.B below. The full text of the Supply Mix Directive is set out in Appendix B.

C. The IPSP Regulation

The Supply Mix Directive states that the IPSP must comply with the IPSP Regulation. As such, the IPSP Regulation has been brought within the scope of the Board's IPSP review mandate.

Like IPSP Directives, the IPSP Regulation articulates Government policy and is binding on the OPA.

II. Principles Guiding Review and Implementation of the IPSP

A. *Board Mandate*

There are three fundamental themes that underlie the statutory framework that governs the IPSP. First, it is the Government, and not the Board or the OPA, which is responsible for articulating the goals that the IPSP is to assist in achieving. Second, those goals go beyond simply ensuring that supply is adequate to meet demand, and the IPSP in that sense is a plan whose scope and purpose is different from that of other, more traditional power system plans. As noted below, the Supply Mix Directive prescribes a mandatory portfolio of supply and conservation resources and addresses other matters that are not, strictly speaking, designed solely to achieve a supply/demand balance purpose. Third, it is the OPA, and not the Board, that has the statutory role of developing the IPSP. These themes direct the tenor of and establish parameters for the scope of the Board's review.

The Board's mandate in relation to its review of the IPSP is to ensure that the IPSP complies with IPSP Directives and that it is, as a whole, economically prudent and cost effective.

The next five sections in this Part address the Board's principles relating to the following:

- The Supply Mix Directive (section B)
- The IPSP Regulation (section C)
- Economic prudence and cost effectiveness of the IPSP (section D)
- The treatment of certain projects that were initiated prior to the date of filing of the IPSP (section E)
- Facilitating implementation of the IPSP (section F)

Section G addresses the general approach to implementation of the IPSP.

B. *The Supply Mix Directive*

The mandate of the Board does not extend to determining whether the goals expressed in IPSP Directives are appropriate, economically prudent or cost effective. Accordingly, the Board will not solicit input on the goals set out by the Government in the Supply Mix Directive.

It will, however, be necessary to consider whether and how the IPSP achieves the goals set out in the Supply Mix Directive in an economically prudent and cost effective manner. Specifically:

Achievement of conservation targets:[1]

The Supply Mix Directive states that the goal for total peak demand reduction from conservation by 2025 is 6,300 MW, with the aim of reducing projected peak demand by 1,350 MW by 2010 and by an additional 3,600 MW by 2025. These reductions are in addition to the 1,350 MW reduction set by the Government as a target for achievement by 2007. The Supply Mix Directive states that the IPSP should assume that "conservation includes continued use by the government of vehicles such as energy efficiency standards under the *Energy Efficiency* Act and the Building Code, and should include load reduction from initiatives such as: geothermal heating and cooling; solar heating; fuel switching; small scale (10 MW or less) customer-based electricity generation, including small scale natural gas fired co-generation and tri-generation, and including generation encouraged by the recently finalized net metering regulation".

The IPSP will need to address how the costs of the different types of conservation measures (e.g., customer-based generation programs or energy efficiency programs) are to be compared in determining which portfolio of measures achieve the conservation targets in an economically prudent and cost effective manner. The conservation targets set out in the Supply Mix Directive is the minimum that must be achieved. An economically prudent and cost effective plan may, however, contain greater quantities of conservation than required by the Supply Mix Directive, provided that those additional investments in conservation are shown to be prudent and cost effective against other resources.

[1] In determining whether the IPSP complies with the Supply Mix Directive, "conservation" must be interpreted as including, in addition to more traditional energy efficiency or demand response programs, the generation measures identified in the Supply Mix Directive. Where a reference to conservation in this Discussion Paper applies only to certain measures (i.e., the reference is not applicable to conservation obtained through generation initiatives), this has been noted.

Achievement of renewable energy targets:[2]

The Supply Mix Directive states that the IPSP should assist the government in meeting its target for 2010 of increasing the installed capacity of new renewable energy sources by 2,700 MW from the 2003 base, and increase the total capacity of renewable energy sources used in Ontario to 15,700 MW by 2025.

The achievement of renewable energy targets allows the economic prudence and cost-effectiveness of different renewable resources to be compared with one another to achieve the renewable energy target in an economically prudent and cost effective manner. The renewable energy targets set out in the Supply Mix Directive are the minimum that must be achieved. An economically prudent and cost effective plan may, however, contain greater quantities of renewable energy than required by the Supply Mix Directive, provided that those additional investments in renewable energy are shown to be prudent and cost effective against other resources.

Use of nuclear energy for baseload:

The Supply Mix Directive states that the OPA should plan for nuclear capacity to meet base-load electricity requirements but limit the installed in-service capacity of nuclear power over the life of the plan to 14,000 MW.

The OPA will need to demonstrate how the IPSP implements the nuclear energy portion of the Supply Mix Directive and whether the means by which any nuclear supply investments will be effected (i.e., by the refurbishment of existing facilities or by the construction of new facilities) are economically prudent and cost effective.

Use of natural gas is in high efficiency, high value applications:

The Supply Mix Directive states that the IPSP should maintain the ability to use natural gas capacity at peak times and to pursue applications that allow high efficiency and high value use of the fuel.

The OPA will need to address how the IPSP allows for the use of natural gas capacity at peak times and enables the pursuit of applications that

[2] The term "renewable energy" is not defined in the Supply Mix Directive. For purposes of the review of the IPSP, this term will be interpreted in a manner consistent with the definition of "renewable energy source" in the Act; namely, "an energy source that is renewed by natural processes, and includes wind, water, a biomass resource or product, solar energy, geothermal energy, tidal forces and any other energy sources as may be prescribed by regulation, provided that the energy source satisfies any applicable criteria as may be prescribed by regulation".

allow high efficiency and high value use of natural gas in an economically prudent and cost effective manner.[3]

Replacement of coal-fired generation:

The Supply Mix Directive states that the OPA should plan for coal-fired generation to be replaced by cleaner sources in the earliest practical time frame that ensures adequate generating capacity and electricity system reliability in Ontario. The OPA is to work closely with the Independent Electricity System Operator (the "IESO") to propose a schedule for the replacement of coal-fired generation, taking into account feasible in-service dates for replacement generation and necessary transmission infrastructure.

The OPA will need to demonstrate how the schedule set out in the IPSP allows for such replacement in the earliest practical time frame while ensuring adequate generating capacity and electricity system reliability, and that the replacement plan is cost effective and economically prudent.

Strengthening of the transmission system:

The Supply Mix Directive states that the IPSP must strengthen the transmission system to: enable the achievement of the supply mix goals set out above; facilitate the development and use of renewable energy resources such as wind power, hydroelectric power and biomass in parts of the province where the most significant development opportunities exist; and promote system efficiency and congestion reduction and facilitate the integration of new supply in a manner consistent with the need to cost effectively maintain system reliability.

The OPA will need to demonstrate how the IPSP provides for the strengthening of the transmission system to achieve these diverse goals. To the extent that strengthening of the transmission system is proposed for purposes of system efficiency and congestion reduction, the OPA will need to identify how and to what degree system efficiency will be improved or congestion will be reduced, as well as the justification for selecting the chosen levels of efficiency and congestion reduction.

Satisfying the requirements of the IPSP Regulation:

The Supply Mix Directive states that the IPSP should comply with the IPSP Regulation.

[3] This element of the Supply Mix Directive is closely linked to a comparable provision in the IPSP Regulation. See section III.C.3(d) below.

The requirements of the IPSP Regulation are addressed in sections II.C and III.F below.

C. *The IPSP Regulation*

While the mandate of the Board does not extend to assessing the adequacy or appropriateness of the provisions of the IPSP Regulation, the Board will need to determine whether the requirements of the IPSP Regulation have been met. A description of, and filing guidelines applicable to, the IPSP Regulation are set out in section III.F.

D. *Economic Prudence and Cost Effectiveness of the IPSP*

Economic prudence requires that the IPSP be sufficiently resilient to ensure that the plan's goals, including goals for adequacy, reliability, renewable energy sources and conservation and demand management, can be achieved in the face of circumstances that turn out differently than assumed in the plan. An economically prudent plan will be able to adapt to different contingencies without causing major changes in overall costs.

As indicated above, it will be necessary to determine whether the goals set out in IPSP Directives have been satisfied in an economically prudent and cost effective manner.

In assessing the IPSP as a whole, the Board will examine the economic prudence and cost effectiveness of the IPSP's main components, particularly those aimed at achieving the goals set out in the Supply Mix Directive. The Board will expect the OPA to demonstrate that it has evaluated alternative ways of achieving those goals, and to satisfy the Board that the selected solutions are individually and collectively economically prudent and cost effective. For example, in order for the OPA to demonstrate that the replacement plan for the coal-fired facilities is economically prudent and cost effective, the IPSP would need to include an assessment of alternative plans. For each alternative, the timing of the replacement for each facility and the associated costs and air emissions would need to be provided.

In the narrowest sense, the cost effective alternative achieves its goals at the lowest overall plan cost as measured on a $/kW or $/kWh basis.

However, the OPA will be required to make trade-offs in preparing the IPSP and to consider or address non-quantitative, non-financial or non-economic factors (such as some of the factors outlined in the IPSP Regulation) in choosing among alternative means of achieving the goals set out in the Supply Mix Directive. The Board accepts, in each case, the alternative chosen may be cost-effective and

economically prudent even if it is not the "least cost" solution. Nonetheless, to the extent that the OPA proposes something other than the "least cost" solution, the onus will be on the OPA to satisfy the Board that this is justified based on relevant considerations other than those of cost or price.

In making these assessments, the Board will require an understanding of the economic and financial cost implications of the IPSP, including the short- and long-term financial impact of IPSP initiatives on electricity system costs and how these might affect provincial electricity prices and rates. The Board will also require an understanding of the financial and other risks associated with IPSP initiatives. Section III.E addresses filing guidelines related to the evaluation of the IPSP as a whole.

The Board is particularly concerned that environmental costs, such as those associated with air emissions, be considered in the development of the IPSP as such costs are not reflected fully in the cost of electricity. The Board will wish to understand how the OPA took environmental externalities into account in considering alternatives ways of achieving the goals set out in the Supply Mix Directive. In this context, however, the Board will not require that environmental costs be measured in dollars. The Board expects that environmental externalities will be addressed in the following manner:

- Environmental externalities should be addressed in a consistent manner for all IPSP resources (transmission investments, generation resources and conservation initiatives);
- Only environmental externalities that are expected to have a significant impact should be included;
- Environmental externalities should be quantified in appropriate physical units, and the assumptions underlying such quantification should be identified;
- Where possible, quantification should be on a life cycle basis; and
- The IPSP will, to the extent practicable, show how environmental externalities will be considered in planning decisions.

E. Pre-IPSP Projects

The economic prudence or cost effectiveness of specific generation or conservation projects that were the subject of governmental procurement or OPA procurement prescribed by Ministerial directive issued prior to the date of approval of the IPSP (for example, the OPA's York region demand response

process or the existing Standard Offer Program) will not be assessed as part of the IPSP review process, even if these projects are included in the IPSP

To the extent that the need for and costs associated with a transmission project are examined in the course of the review of a transmitter's capital budget in a rates proceeding or in the course of a leave to construct proceeding that is pending prior to approval of the IPSP, these issues will not be assessed a second time as part of the IPSP review process even if the project is included in the IPSP.

F. Facilitating Implementation of the IPSP: Regulatory Consistency and Streamlining

Section 1(2) of the *Ontario Energy Board Act, 1998* (the "OEB Act") states that the Board must facilitate the implementation of an approved IPSP when it exercises and performs its statutory duties. This obligation is a driving force in favour of regulatory streamlining in relation to those of the Board's statutory duties that may overlap with matters considered by the Board in its review of the IPSP. Streamlining, in this context, does not mean that applicable regulatory approvals will necessarily be avoided. Rather, requiring that a detailed rationale for electricity projects be provided in the IPSP can result in the creation of an analysis that can be relied upon by an electricity project proponent in addressing the scope of subsequent regulatory review.

Regulatory streamlining opportunities will therefore be sought in relation to projects that are examined as part of the Board's review of the IPSP, and the IPSP review proceeding will be used to address as many issues as is feasible in relation to proposed projects that would otherwise be reviewed on a case-by-case basis as part of another of the Board's statutory functions. In other words, issues that are adequately addressed in the context of the IPSP will not be subject to re-examination by the Board at a later date. Parties with an interest in those issues must therefore ensure that their positions are brought forward during the IPSP proceeding. As noted below, it is expected that the OPA will use its consultation process to foster a greater and more widespread understanding of this approach.

The potential for streamlining is greatest in relation to the Board's regulatory approvals associated with transmission system investments. Traditionally, these include a review of transmission investment costs (as part of a transmitter's capital budget in a rates proceeding) and the Board's approval of applications for leave to construct transmission facilities. To the extent that the need for and costs associated with a project are assessed by the Board in the context of the IPSP, those issues will not thereafter be revisited except in relation to any material deviations. If the likelihood of obtaining the benefits of the streamlined approach to transmission system investments noted above were to be

maximized, the rationale for a project would need to be at a level of detail at least equal to that which would be required to satisfy the requirements of the Board's review of a transmitter's capital budget in a rates proceeding or the Board's approval of an application for leave to construct transmission facilities.

As there are no exclusive franchises for electricity transmission in Ontario, any major new "greenfield" transmission initiatives identified in the approved IPSP may bring forward more than one potential transmission developer, subject to existing land use rights and rights arising from the ownership of existing transmission infrastructure. It may therefore be necessary for the Board to ultimately determine who should provide transmission infrastructure and service in such cases.

With respect to streamlining in relation to gas pipelines that may be required by gas-fired generators, it is not expected that the IPSP review proceeding will be used to address gas pipeline infrastructure issues that the Board typically considers in the context of pipeline leave to construct applications. These would continue to be dealt with in the context of leave to construct proceedings.

G. Implementation of IPSP Initiatives

It is important that there be accountability for implementation of the IPSP. The OPA and other parties that are regulated by the Board will therefore be expected to work diligently towards implementation of initiatives that have been included in the approved IPSP. Consideration may be given to using the regulatory tools that are at the Board's disposal (such as the imposition of licence conditions) as required or appropriate to facilitate the implementation of projects identified in the IPSP.

In the event that there is a potential material deviation from the IPSP, the OPA (or the party responsible for implementation of an initiative) will be expected to notify the Board accordingly so that the need for an update to the IPSP or other action may be considered. Similarly, it is expected that the Board will be kept apprised of impediments or obstacles to implementation of IPSP initiatives, as well as of the means by which those impediments or obstacles might be overcome.

It follows from the above that the OPA will be expected to monitor the implementation and evaluate the effectiveness of IPSP initiatives on an on-going basis. The OPA will also be expected to provide the Board with periodic updates regarding IPSP implementation between triennial reviews of the IPSP, which the Board will make available to the public. The timing of such updates will be determined in the course of the Board's IPSP review hearing.

III. IPSP Filing Guidelines

A. Introduction

In the Board's IPSP review proceeding, the onus will be on the OPA to demonstrate to the satisfaction of the Board that the IPSP complies with the IPSP Directives and the IPSP Regulation, and that it is economically prudent and cost effective.

This Part sets out expectations regarding the OPA's IPSP filing as follows:

- Section B describes expectations of a general nature that apply to the IPSP as a whole
- Section C contains filing guidelines regarding the acquisition of conservation, generation and transmission resources for the period covered by the Near-term Plan
- Section D contains filing guidelines regarding the acquisition of those resources for the period beyond the years covered by the Near-term Plan
- Section E sets out information that will be required in order for the Board to consider the economic prudence and cost effectiveness of the IPSP as a whole
- Section F sets out the information that will be required in order for the Board to determine whether the requirements of the IPSP Regulation have been satisfied

B. General

1. Level of Detail

It is expected that considerable detail will be provided in relation to solutions or initiatives that are proposed for implementation in the earlier years of the IPSP. It is not realistic to expect that same level of detail in relation to the later years of the IPSP. Since the IPSP must be updated every three years, the following solutions or initiatives (the "Near-term Plan") must be identified with a high level of detail:

- in the case of transmission resources, those for which the approval process under section 92 of the OEB Act must be commenced prior to the end of 2010; and

- in the case of generation or conservation resources, those which the OPA intends to procure prior to the end of 2010.

While a more conceptual level is expected for the later years, it must be sufficient to enable the Board to understand the integrated nature of the IPSP over the longer term.

2. Third Party Input

The OPA must present a realistic assessment of the initiatives identified in the IPSP. Those initiatives must realistically be able to be implemented within the specified timeframe, particularly in the case of initiatives identified as part of the Near-term Plan. This can only be achieved if the IPSP reflects all necessary input from the IESO, transmitters and other relevant parties. The Board expects the OPA to make all reasonable efforts to obtain the required information from third parties, but acknowledges that the ability of the OPA to satisfy the filing guidelines set out below is in some cases dependent on the timely provision of information by third parties.

The Board reminds electricity licensees that, in accordance with section 70(7) of the OEB Act, they are required by condition of licence to provide such reasonable information to the OPA as the OPA may require, in the manner and form specified by the OPA.

3. Demand and Supply Forecasts and Adequacy Assessments

In assessing the economic prudence and cost effectiveness of the IPSP, the extent to which new resources (transmission, generation and conservation) are necessary in order to meet overall power and system needs during the period covered by the IPSP will need to be considered. Forecasts of demand and supply will therefore be required, as well as assessments of the adequacy of resources to satisfy demand at any given time. The OPA will be expected to identify the supply gap for the province under different scenarios, and to describe how and why its forecasts might differ from other published forecasts, such as those prepared by the IESO. In addition, comparison should also be made between the key economic drivers used by the OPA in its forecasts and those used in other forecasts.

For each year covered by the Near-term Plan, and biennially for the period beyond that covered by the Near-term Plan, the OPA should identify:

i. the net load growth, including the peak load component, after separately accounting for:

a. end-use and economic load growth as identified in studies conducted by the OPA and others for this purpose;

b. load reduction resulting from "natural conservation" (i.e., the effect of ongoing energy efficiency and conservation improvements in building codes, household appliances and the like) disaggregated, to the extent feasible, by separately identifying applicable influences (such as price and regulatory and market influences); and

c. on-site load displacement generation that has not already been accounted for elsewhere in the IPSP (i.e., already included as a conservation resource);

d. increases or decreases in system reliability margins;

ii. generation capacity assumed to exist at the relevant time, and the basis for the assumptions made in that regard;

iii. transmission capacity assumed to exist at the relevant time, and the basis for the assumptions made in that regard;

iv. the resultant adequacy assessment that identifies shortfalls in generation or transmission capacity that will need to be met through "project-specific" conservation activities (i.e., specific targeted conservation initiatives - locally or system-targeted - undertaken by the OPA), transmission system expansions or improvements and/or investments in or purchases of generation.

It is expected that the load forecasts utilized by the OPA and filed for purposes of the IPSP review will:

i. identify the load growth (or decline) assumptions by region, for the province as a whole;

ii. include annual regional forecasts for each year covered by the Near-term Plan for both energy and capacity requirements;

iii. include biennial provincial forecasts for the period beyond that covered by the Near-term Plan for both energy and capacity requirements;

iv. identify the load growth or decline assumptions associated with electricity commodity prices over the relevant planning period;

v. include a range of forecasts - together with the likelihood of each forecast - to reflect possible future load changes resulting from various economic and end-use scenarios; and

vi. separately identify the impact of natural conservation on the forecasts, together with applicable assumptions;[4]

vii. be expressed in weather-corrected terms, together with a description of the methodology employed;

viii. identify the effects of extreme weather; and

ix. include the effects of commodity, fuel price and price elasticity to the extent that these are significant.

The OPA will also be expected to provide the following in relation to the plan:

i. a description of the load growth scenario(s) being assumed (e.g. end-use increases/decreases and low, median or high economic growth) and the forecast methodology employed;

ii. a description of the load reduction activities being assumed as a result of conservation initiatives, and the forecast methodology employed for identifying separately "natural conservation" improvements and the impact of "project-specific" conservation activities;

iii. the specific level of transmission system reliability/adequacy and generation reserve margins selected by the OPA;

iv. a description of the methodology and metrics used for determining the generation reserve margin and the transmission system reliability/adequacy requirements, and the justification for the selected methodology and metrics; and

v. the assumptions being made about the remaining operating lives of existing facilities, and the basis for the assumptions made in that regard.

C. Resource Planning and Acquisition: The Near-term Plan

It is anticipated that the IPSP will call for investment in three types of resources; namely, generation resources that provide additional power supply to the transmission system, conservation resources that reduce electricity system supply requirements, and transmission resources that support the other resources or substitute for them.

[4] This does not apply in relation to conservation resource initiatives in the form of generation.

Resource planning and acquisition/investment is one area where it is expected that there will be considerably more detail in relation to the period covered by the Near-term Plan than will be the case for the remaining period covered by the IPSP. Furthermore, the Near-term Plan will be strongly affected both by existing resource initiatives and by the near-term targets set out in the Supply Mix Directive.

1. General

This section sets out information requirements that apply to all resource investments identified in the Near-term Plan. The following sections contain additional information requirements for each type of resource: conservation (section 2), generation (section 3) and transmission (section 4).

This general section and those that follow contemplate that the OPA will have identified resources based on a consideration of alternatives. In this regard, it is expected that the OPA will consider and present, where applicable, the smallest number of alternatives consistent with conveying to the Board the major concepts available to meet the same objectives as those that are met by the preferred option.

In presenting the resource acquisition/investment portion of the Near-term Plan, it is expected that the OPA will:

i. identify the total need for resources and associated timelines;

ii. indicate the allocation between generation and conservation resources, as well as the rationale for that apportionment;

iii. where one resource solution has been preferred over an alternative resource solution (whether of the same or a different type), identify the rationale for selecting the preferred solution in terms of factors such as costs, financial risks to be assumed by electricity consumers, benefits, reliability and quality of service;

iv. describe the critical preliminary work, consultations or substantive approvals that must be undertaken or obtained, as well as the costs and timetable associated with those activities;

v. when identifying the cost associated with the acquisition of resources, set out the assumptions made in relation to the sharing of risks between the OPA and consumers, on the one hand, and the entity providing the resource, on the other; and

vi. express the costs in a consistent manner for all generation and conservation resources (i.e., cost per MW or MWh supplied or not consumed).

The OPA should also identify the manner in which it expects or proposes that a generation or conservation resource will be procured or acquired, where known, and the basis upon which the OPA believes that the process will result in the economically prudent and cost effective procurement of the resource.[5] Where a procurement process is proposed to be used, the OPA must identify the nature of the procurement process. In the case of transmission resources, the entity that will be making the transmission resource investment must be identified if known.

In estimating the total costs of a resource, the OPA must identify and include the costs associated with the method of obtaining the resource.

Further discussion is warranted in relation to proposals for obtaining a resource using a process other than a contract-based procurement mechanism, such as a proposal to obtain demand response by means of an auction or a series of auctions. Specifically, the costs associated with using a process other than a contract-based mechanism can be more diverse than those associated with a contract-based procurement process, and these should be identified and quantified. For example, there may be costs associated with:

i. the development of and compliance with new or additional legal or regulatory requirements (such as market rules, licences, codes, etc.);

ii. the need for new infrastructure if the mechanism cannot be supported by existing infrastructure or new infrastructure that is known to be required for other purposes (such as wholesale market settlement systems and distribution customer information and billing systems);

iii. the stranded costs associated with the mechanism if it cannot be accommodated by existing infrastructure or new infrastructure that is known to be required for other purposes; and

iv. the need for existing and potential market participants to acquire new skills or resources.

Where transition costs result from a shift from contract-based supply to non contract-based supply, this must be identified and the costs quantified where possible.

[5] This is not intended to prohibit the OPA from using a different procurement process than that originally intended if circumstances warrant such a change. As noted in section II.B, the Board expects that the OPA will articulate in its procurement process filing the circumstances in which it may need to switch from one form of procurement to another.

The use of mechanisms that are not contract-based can carry benefits, and these should also be identified and quantified. For example, they may:

i. enhance consumer choice for electricity products and services;

ii. enhance electricity commodity price stability;

iii. reduce or limit increases in regulatory charges; and

iv. shift the commodity risk away from consumers.

Where use of a non contract-based mechanism for obtaining resources is proposed, the following additional information will also be required:

i. an evaluation of the ability of existing and potential market participants to assume the financial and operational risks associated with the initiative, including a consideration of creditworthiness criteria; and

ii. an assessment of the degree to which the mechanism will either reduce or create new or additional barriers to entry or participation for existing and potential market participants.

2. Conservation Resources

The IPSP must propose a portfolio of conservation resource initiatives that will achieve the short-term and long-term targets set out in the Supply Mix Directive.

For specific conservation resource initiatives, the OPA must identify:

i. the initiative by sector and by end-use;

ii. the criteria used by the OPA in evaluating, selecting and prioritizing the conservation initiatives that are being put forward; and

iii. the manner in which the OPA will evaluate, monitor and verify the contribution to reductions in peak energy demand (and, where applicable, energy consumption) from the conservation initiatives.

In valuing a conservation resource initiative, the OPA must take into account any conservation investments that would have been made in the absence of the initiative (in other words, free-ridership).

For each proposed conservation resource initiative that is not in the form of generation, the OPA must identify the following:

i. the full capital and operating cost (per unit of demand and/or consumption) expected to be associated with implementation of the resource initiative, regardless of the person that bears the costs;

ii. the savings (in demand and/or consumption) expected to be associated with implementation of the resource initiative, including the timing and persistence of those savings;

iii. a description of the major assumptions that underlie the OPA's determination of the expected costs and savings referred to above;

iv. whether the resource initiative is intended principally to address local area reliability or supply issues; and

v. how the conservation resource initiative will be procured and from which sector, and at which end use it is targeted.

For each proposed conservation resource initiative that is in the form of generation, the OPA must provide the information set out in the applicable portions of section 3 below.

3. Generation Resources

a) *General*

Specific generation resource acquisition initiatives must be identified in addition to the total supply mix being acquired. This section sets out information requirements that apply to all types of generation resources. The following sections contain additional information requirements for each type of generation resource: renewable energy (section (b)), nuclear (section (c)), gas-fired (section (d)) and resources outside of Ontario (section (e)).

The criteria used by the OPA in evaluating, selecting and prioritizing the generation resource initiatives that are being put forward must be identified.

For each proposed generation resource initiative, the OPA must identify the following:

i. size (capacity), fuel source, capacity factor and general location of the resource (including an indication of distance from existing transmission or distribution system facilities and loads) and the rationale for that location;

ii. an estimate of the full cost of the project (i.e., construction, delivered fuel. operation, waste disposal and decommissioning) to the extent available, including the directly attributable cost of transmission or distribution investments that would be necessary to incorporate and deliver energy

from the project to the network. The most significant cost elements should be expressed as range estimates (e.g., plus/minus one standard deviation);

iii. an estimate of the impact of the resource on transmission constraints and congestion costs;

iv. an estimate of any impact (other than a transmission rate or congestion cost impact) of the project on existing affected transmission customers, including system losses where applicable;

v. a description of the major assumptions that underlie the OPA's determination of the estimated costs referred to above;

vi. an estimate of the in-service date of the project and an assessment of the risk of project delays;

vii. an assessment of the economic and financial risks associated with the project that is commensurate with the magnitude of the project, including in relation to such factors as additional investments in existing facilities, project delays and uncertainty regarding fuel costs;

viii. whether the resource initiative is intended principally to address local area reliability or supply issues;

ix. the capability factor of the generation facility on an annual basis and, where relevant, on a seasonal and daily basis;

x. the level of dispatchability of the generation resource, and any measures for enhancing dispatchability or load following capabilities or for mitigating intermittency;

xi. the life expectancy of the generation resource;

xii. how the generation resources will be procured, if applicable; and

xiii. all substantive approvals and permits that would be required to construct and operate the resources.

b) *Renewable energy generation resources*

The IPSP must propose a portfolio of renewable energy resource development measures that will meet the short-term and long-term targets set out in the Supply Mix Directive.

For each generation resource initiative that targets generation from renewable energy sources, the OPA must identify:

i. the eligible fuel sources; and

ii. the OPA's expectations or assumptions regarding acquisition of generation from each type of fuel source.

c) *Nuclear generation resources*

The IPSP must include a plan for using nuclear energy to meet base-load electricity requirements, up to a maximum of 14,000 MW of installed, in-service capacity. To address this, the OPA must provide:

i. an assessment of the level of base-load generation required over the forecast period, and the gap between that forecast and existing resources available to serve base-load;

ii. an economic assessment of the feasible refurbishment or additions of new nuclear power capacity up to the 14,000 MW ceiling; and

iii. an assessment of the economic and financial risks associated with life extension options for existing nuclear facilities and for new nuclear facilities.

The Government has directed Ontario Power Generation Inc. ("OPG") to begin a feasibility study on the refurbishment of its existing facilities to review the economic, technological and environmental aspects of refurbishment.[6] OPG has also been directed to begin the environmental assessment process for the construction of new units at an existing nuclear facility.

To the extent that the results of these activities are known at the relevant time, it is expected that they will be made available to and considered by the OPA in the development of the IPSP.

d) *Gas-fired generation resources*

Paragraph 3 of section 2(1) of the IPSP Regulation requires the OPA to identify opportunities to use natural gas in high efficiency and high value applications in electricity generation. These applications appear to be the same as, or at least a

[6] On August 3, 2006, OPG announced that it will proceed with an environmental assessment as part of its business case study for a potential refurbishment and life extension of its Pickering B nuclear plant, and that an environmental assessment report on the matter could be ready by 2007.

subset of, the applications that allow high efficiency and high value use of natural gas that the OPA is required to pursue under the terms of the Supply Mix Directive. Accordingly, the opportunities must be realistic from a physical and commercial perspective. In order to evaluate whether the requirements of this element of the IPSP Regulation and the Supply Mix Directive have been met, the OPA will be required to identify:

i. the criteria that it has used to determine whether an application is high efficiency and high value;

ii. the economic potential for such generation, above what may be included in contracts listed in the *Prescribed Contracts re Sections 78.3 and 78.4 of the Act Regulation*, O. Reg. 578/05; and

iii. any barriers to the pursuit of those applications, as well as the means by which those barriers can be eliminated.

e) *Generation resources outside of Ontario*

For each generation resource initiative that targets generation resources located outside the province, the OPA must identify:

i. all significant agreements that would need to be entered into in order to allow for the construction and operation of the project, and the status of those agreements, if known; and

ii. how and, if known, by whom associated transmission investments will be secured.

4. Transmission Resources

Transmission resource initiatives associated with generation resource initiatives are addressed in section 3 above. As noted in that section, the following estimated costs should be identified separately for each of the following:

i. the directly attributable cost of the transmission investments that would be necessary to incorporate and deliver energy from the generation resource to the network;

ii. the impact of the generation resource on transmission constraints and congestion costs; and

iii. the impact (other than a transmission rate or congestion cost impact) of the project on existing customers.

The remainder of this section addresses transmission system initiatives that are proposed to address the requirements outlined in the Supply Mix Directive to strengthen the transmission system.

For each such transmission resource initiative, the OPA must:

i. identify the need for the resource initiative (for example, to comply with a reliability standard; to meet anticipated load growth; to reduce transmission congestion costs, etc.) and the relationship between the initiative and other projects it immediately supports and/or that it is supported by;

ii. provide a description of the transmission resource initiative, including the length and capacity of the transmission line if known, routing or general siting information and an estimate of the total project cost;

iii. provide a description of each phase of the project, together with a year-by-year time schedule until the planned in-service date;

iv. provide a schedule of estimated costs, broken down as set out in item ii above, associated with the project that meets the following requirements:

   a. costs must be expressed in dollars of the year;

   b. acquisition/capital costs and interest costs must be identified separately and expressed as a single best estimate (point estimate) and as a range estimate (e.g. plus/minus one standard deviation) cumulatively until the planned in-service date; and

   c. annual costs must be specified, including operating and maintenance costs;

v. where the resource initiative is required in order to meet a system reliability standard, identify the standard, as well as any material underlying assumptions or issues in relation to the interpretation or application of that standard; and

vi. where the resource initiative is required or desired for another purpose, identify and quantify the benefits associated with the investment. Such other purposes could include reducing transmission system losses, reducing congestion, increasing generation reserve margins or enhancing the flexibility of transmission system operations and maintenance.

In relation to each transmission resource that is proposed for the purpose of meeting a system reliability standard, the OPA must demonstrate that the proposed solution offers the greatest net benefit of all alternatives considered. In relation to each transmission resource that is not designed for the purpose of meeting a system reliability standard, or is designed to exceed a system reliability standard, the OPA must demonstrate that the benefits of the resource exceed its costs, and that the proposed solution offers the greatest net benefit of all alternatives considered.

D. Resource Planning and Acquisition: Beyond the Near-term Plan

As noted earlier, solutions or initiatives for years beyond the period covered by the Near-term Plan are expected to be presented at a more conceptual level. In this regard, the following is expected in relation to resource planning and acquisition:

i. identification of the need for resources;

ii. the anticipated composition of the resource portfolio (generation, conservation and transmission) and, for the generation resource element, the anticipated composition of the generation resource portfolio in terms of capacity, fuel source, technology and similar distinguishing features; and

iii. the rationale used to arrive at the portfolio compositions, including a general description or assessment of the following, in as much detail as practicable:

   a. expected direct costs (such as capital and commodity costs);

   b. expected method of procurement or acquisition;

   c. expected in-service or availability dates;

   d. expected or potential location of resources or, in the case of non-generation conservation resources, the persons or class of persons targeted to deliver the resources;

   e. integration implications (such as associated transmission or distribution system upgrades); and

   f. material risks and uncertainties related to the feasibility of the portfolio compositions (such as uptake under the standard offer program, technological advances, performance under existing contracts, changes in demand growth, resource intermittency and the need for regulatory approvals).

E. The Overall Plan

It is expected that the OPA will identify a single preferred IPSP, including an implementation schedule that articulates when, how and, if known, by whom key initiatives will be undertaken.

The OPA should provide a description of the plan, including conservation, generation and transmission resource initiatives, together with the following:

i. the evaluation criteria (economic, environmental and social) used in developing the plan and the manner in which the criteria were applied;

ii. the year-by-year cumulative resource acquisition/capital cost and, separately, the interest cost for the plan, each expressed as a single best estimate (point estimate) and as a range estimate (e.g. plus/minus one standard deviation), with all costs expressed in dollars of the year;

iii. the net present value ("NPV") for the plan, expressed as a single best estimate (point estimate) and as a range estimate (e.g. plus/minus one standard deviation), with all NPV calculations being stated in dollars of a single base year. The NPV must include all applicable costs and the discount rate used must be justified;

iv. the estimated impact on wholesale electricity prices and on transmission revenue requirements (in percentage terms), expressed as a single best estimate (point estimate) in each year and as a range estimate (e.g. plus/minus one standard deviation) in each year;

v. generating capacity vs. transmission capacity trade-offs, generation location vs. additional transmission trade-offs, schedule acceleration vs. deceleration trade-offs, and other resource trade-offs; and

vi. an analysis of the plan's flexibility/robustness to changes in implementation schedule; and

vii. a supporting sensitivity analysis, including all financial risks, high and low forecast risks and other significant risks;

viii. an indication of how those risks will be managed;

ix. a demonstration of how the plan can address a range of contingencies such as unexpectedly rapid or slow growth in electricity demand and material deviations in fuel prices; and

x. the estimated air emissions associated with the plan.

F. Satisfying the Requirements of the IPSP Regulation

Section 2(1) of the IPSP Regulation sets out responsibilities that the OPA must fulfill in developing the IPSP. These responsibilities largely fall into the categories of:

- plan preparation;
- alternatives to OPA procurement; and
- environmental issues.

Each of these are described in turn below. The element of the IPSP Regulation that relates to the use natural gas in high efficiency and high value applications in electricity generation is discussed in section III.C.3(d) above in the context of the acquisition of gas-fired generation resources.

1. Plan Preparation

Two paragraphs of section 2(1) of the IPSP Regulation (1 and 7) require the OPA to consider certain things in developing the IPSP. This section outlines what is expected of the OPA with respect to those considerations.

In its original form, paragraph 7 of section 2(1) of the IPSP Regulation required that the OPA ensure that safety and economic and environmental sustainability and environmental protection be "reflected" in the IPSP. The paragraph was subsequently amended to remove the reference to economic sustainability and to require that the remaining matters be "considered" by the OPA rather than "reflected" in the IPSP. For purposes of paragraphs 1 and 7 of section 2(1) of the IPSP Regulation, the Board therefore interprets the term "considered" as meaning weighed and evaluated.

Paragraph 1 of section 2(1) of the IPSP Regulation requires that the OPA consult certain persons and consider their priorities and views in developing the IPSP. The OPA will therefore be required to describe the consultation process that it followed in developing the IPSP, including a list of the persons consulted, an indication of how those persons' priorities and views were determined and an indication whether and the extent to which the OPA revised its approach in light of those priorities and views. The OPA should ensure that it makes key information associated with the IPSP available to interested parties as soon as the information becomes available to ensure that its consultations are as meaningful as possible. The OPA should also ensure that, through its consultation process, it is made clear to interested parties that the need for certain projects (i.e., projects identified in the Near-term Plan that are not already the subject of review in a rates proceeding or a leave to construct proceeding)

will be addressed as part of the IPSP review and may not be reconsidered by the Board after that time.

Paragraph 7 of section 2(1) of the IPSP Regulation requires the OPA to ensure that safety, environmental protection and environmental sustainability are considered in developing the IPSP. Thus, the OPA will be required to indicate how it has considered these matters in developing the IPSP. The OPA will also be required to demonstrate whether and the extent to which the IPSP was affected by a consideration of these matters as well as the basis upon which the OPA determined how implementation of the IPSP will be as predicted with respect to these matters.

The OPA should, in developing the IPSP, use the following definitions for each of the terms set out in paragraph 7 of section 2(1) of the IPSP Regulation:

Safety:

Refers to the safety of workers and members of the public through compliance with all applicable Ontario and federal laws and regulations pertaining to the construction and operation of facilities identified in the IPSP, including regulations and requirements of the Electrical Safety Authority and of the Canadian Nuclear Safety Commission.

Environmental protection:

Refers to the identification of adverse effects on the environment that an electricity project and identified alternatives to it may have and the measures that will be applied to mitigate those adverse effects in compliance with all applicable Ontario and federal laws and regulations related to environmental protection.

Environmental sustainability:

Refers to development that ensures that the needs of the present are met without compromising the ability of future generations to meet their own needs.

2. Alternatives to OPA Procurement

Paragraphs 5 and 6 of section 2(1) of the IPSP Regulation speak to the use of procurement processes and associated procurement contracts by the OPA – the former in relation to measures that can reduce reliance on those processes and the latter in relation to circumstances in which those processes should be engaged. This recognizes that OPA procurement processes and procurement contracts are not the sole means by which the supply and conservation goals set

out in an IPSP Directive may be achieved, and that realistic alternative means may be more cost effective. Those alternative means are embodied in the concept of the "innovative strategies" referred to in paragraphs 2 and 4 of the IPSP Regulation. This means that realistic and cost-effective alternatives to OPA procurement can be addressed in the IPSP, and interested parties should be encouraged to identify alternatives as part of the OPA's consultation process.

For purposes of these four elements of the IPSP Regulation, the OPA will be required to:

i. identify alternatives to reliance on OPA procurement processes for the purposes of meeting the conservation and supply goals set out in IPSP Directives, and indicate how each such alternative will reduce reliance on OPA procurement processes:

ii. for each innovative strategy that is identified and developed to accelerate the implementation of conservation, energy efficiency and demand management measures, identify how implementation would be accelerated relative to implementation by way of OPA procurement process;

iii. for each innovative strategy that is identified and developed to encourage and facilitate competitive market-based responses and options, identify how the alternative would encourage and facilitate those responses and options and how they would assist in meeting overall system needs. The OPA is expected to describe the merits and disadvantages of different options, and might identify a process for further development of those options; and[7]

iv. for the factors to be considered in determining that it is advisable to enter into procurement contracts for conservation or supply, identify how and why each factor was determined to be relevant to this determination.

To the extent that the IPSP contemplates implementation of an innovative strategy referred to above, the OPA will be required to identify the following:

i. the costs and benefits associated with the innovative strategy relative to the costs and benefits associated with use of the OPA's procurement processes; and

ii. barriers to implementation of the innovative strategy, as well as the means by which those barriers can be mitigated or eliminated.

[7] Section III.C.1 contains a discussion of some of the costs and benefits that could be associated with non contract-based procurement mechanisms.

3. Environmental Issues

Paragraph 8 of section 2(1) of the IPSP Regulation requires the OPA to ensure that, for certain "electricity projects" (transmission line, generation facility, distribution station or transformer station) that are proposed in the IPSP, the IPSP contains a sound rationale including: (i) an analysis of the impact of the project on the environment; and (ii) an analysis of the impact on the environment of a reasonable range of alternatives to the project. For purposes of this paragraph of the IPSP Regulation, "environment" is defined as "air, land, water, plant life and animal life, including human life", and "environmental" has a corresponding meaning.

The sound rationale must be included for electricity projects that require an environmental assessment under Part II of the *Environmental Assessment Act* and for which an application for approval under that *Act* will have to be made within five years after approval of the IPSP by the Board in order to meet the completion date for the project set out in the IPSP. Nuclear generation projects as well as some others are outside the scope of this paragraph of the IPSP Regulation.

Paragraph 8 of section 2(1) of the IPSP Regulation can have the effect of facilitating the streamlining of regulatory approvals associated with electricity projects that are subject to provincial environmental assessments. Streamlining, in this context, does not mean that applicable regulatory approvals will be avoided. Rather, by requiring that a sound rationale for electricity projects and alternatives to those projects be provided, this paragraph of the IPSP Regulation can result in the creation of an analysis that can be relied upon by a future electricity project proponent in addressing the scope of subsequent environmental assessments.

For purposes of this paragraph of the IPSP Regulation, the OPA will be required to:

i. identify each electricity project that meets the criteria set out in section 2(2) of the IPSP Regulation and explain the basis for that determination;

ii. describe the following for each electricity project identified in item i above:

   a. the environment that will or might reasonably be expected to be directly or indirectly affected by the electricity project;

   b. the effects that the electricity project will or might reasonably be expected to have on the environment; and

c. the actions that are or might reasonably be expected to be required in order to prevent, change, mitigate or remedy the effects referred to in item b above;

iii. identify a reasonable range of alternatives to each electricity project identified in item i above;

iv. describe the elements set out in item ii above for each alternative identified in item iii above; and

v. for each electricity project, provide a comparative evaluation of its environmental impact relative to the alternatives identified for that project.

If the likelihood of obtaining the benefits of the streamlined approach to environmental assessments noted above were to be maximized, the sound rationale would need to be at a level of detail at least equal to what would be required to satisfy the requirements of the *Environmental Assessment Act* in respect of the description of, and the statement of the rationale for, each project and alternatives to each project

It is expected that environmental externalities will be addressed as part of the analysis required by paragraph 8 of section 2(1) of the IPSP Regulation. Externalities should be addressed consistently for each electricity project identified by the OPA as meeting the requirements of section 2(2) of the IPSP Regulation and for each alternative to that project identified by the OPA.

The analysis described in this section F.3 should, at a minimum, be conducted as part of the resource planning and acquisition selection process described in sections III.C and III.D above, and in particular in the evaluation of generation and transmission resources.

PART TWO: PROCUREMENT PROCESSES

I. Introduction

Under section 25.31 of the Act, the OPA is required to develop "appropriate procurement processes for managing electricity supply, capacity and demand" in accordance with its approved IPSP. The procurement processes must provide for simpler procurement processes for supply or capacity to be generated using alternative energy sources or renewable energy resources, or both, where the supply or capacity of the facility or unit satisfies the prescribed conditions.

Further guidance regarding the OPA's procurement processes is found in the *Ontario Power Authority Procurement Process Regulation*, O. Reg. 426/04 (the "Procurement Process Regulation").

Once the OPA's procurement processes have been approved by the Board, the OPA may enter into "procurement contracts" in accordance with those procurement processes, subject to the constraints imposed by the Act and the Procurement Process Regulation. Procurement contracts are described in section 25.32(1) of the Act as contracts for: "(a) electricity supply or capacity, including supply or capacity to be generated using alternative energy sources, renewable energy sources or both; or (b) measures that will manage electricity demand or result in the improved management of electricity demand on an on-going or emergency basis".

Because recovery by the OPA of its costs and payments related to procurement contracts is deemed by section 25.20(4) of the Act to be approved by the Board, those costs and payments are automatically passed through to electricity consumers.

Appendix C contains excerpts from the Act that relate to the OPA's procurement processes, as well as the provisions of the Procurement Process Regulation.

II. Principles Guiding Review of Procurement Processes

A. Board Mandate

The Act requires that the OPA's procurement processes be appropriate for the purpose of managing electricity supply, capacity and demand in accordance with the approved IPSP. The Act also requires that the OPA's procurement processes provide for simpler processes for electricity supply or capacity to be generated using alternative energy sources or renewable energy sources, or both, where the supply or capacity or the generation facility or unit satisfies the prescribed conditions.

The Procurement Process Regulation establishes parameters for the development of those processes and allows the OPA a degree of flexibility in relation to certain elements. For example, the Procurement Process Regulation favours but does not mandate competitive procurement processes. The Procurement Process Regulation also contemplates that the IPSP will identify factors to be considered by the OPA in respect of the advisability of entering into procurement contracts.

The Board has been guided by the provisions of Act and of the Procurement Process Regulation in developing the procurement process elements set out in section B below.

The Standard Offer Program[8] is a form of procurement process. On March 21, 2006, the Minister of Energy issued a directive to the OPA under section 25.32 of the Act directing the OPA to assume responsibility for certain aspects of the Standard Offer Program. The stated expectation is that the OPA will enter into such contracts as are necessary to implement the Standard Offer Program. The Board does not intend to review the Standard Offer Program within the scope of its review of the OPA's procurement processes.

B. Procurement Process Elements

1. General

Procurement processes should:

i. be fair and transparent;

ii. be designed to limit barriers to participation;

[8] See the March 17, 2006 joint report of the Board and the OPA to the Minister of Energy entitled *Recommendations on a Standard Offer Program for Small Generators Connected to a Distribution System.*

iii. be as simple as the circumstances allow;

iv. restrict the use of confidentiality provisions to the maximum extent possible; and

v. make provision for the results of the procurement process to be disclosed to the public on a timely basis.

There are three forms of procurement process that can be anticipated to be used by the OPA – competitive processes (i.e., open tenders), non-competitive processes (i.e., single source procurement) and standard offer processes. Competitive processes may be addressed to the public generally, to all persons within a particular class (i.e., to all licensed distributors or to all licensed generators) or to a list of pre-identified prospective proponents having known qualifications. Non-competitive processes are those in which formal competitive processes are not used to select among bids. Standard offer processes are those for which standard contract terms and conditions are made available to all interested and qualified proponents with technically feasible projects, subject to any ceiling or cap that may be in place.

It is expected that competitive procurement processes will be used in the normal course, and that non-competitive procurement processes will be used on an exceptional basis (for example, in cases of urgency). To the extent that the OPA anticipates that it may need to use a non-competitive process in circumstances where a competitive one was initially intended, the criteria for doing so must be clearly identified.

Because standard offer processes can carry the risk of higher consumer prices and less than optimal deployment of resources, mechanisms must be in place to minimize that risk.

The Act requires that the OPA's procurement processes provide for simpler processes for electricity supply or capacity to be generated using alternative or renewable resources where the supply or capacity or generation facility or unit satisfies the prescribed conditions. Therefore, the OPA will need to demonstrate how its procurement processes for such resources are simpler than procurement processes for other resources to the extent that the necessary conditions have been prescribed and are met.

2. Competitive Procurement

Competitive procurement processes are expected to be used in the normal course, and should:

i. identify the resource being procured and, where applicable, the region in which the resource is required to be located. For generation resources, this should include eligible fuel sources and minimum capacity and output parameters, as well as the total number of MW to be procured under the process. For conservation resources, this should include a description of the eligible conservation activities (such as demand response, load shifting or behind the meter generation) and the total number of MW to be procured in relation to each;

ii. identify the criteria that will be used to evaluate each proposal, how those criteria will be applied or evaluated and the weight given to each criterion. The criteria must be applied in a consistent and fair manner to all proponents, and should include the following:

a. date of availability of the resource;

b. type and status of project financing;

c. creditworthiness or financial strength of the proponent;

d. need for and status of substantive project and site approvals or permits;

e. need for and status of acquisition of land use rights;

f. for generation resources, all indirect costs (such as the extent of any costs associated with any necessary network investments, waste disposal or remediation costs, etc.) and all indirect benefits (such as congestion reduction);

g. for generation resources, the impact on affected transmission or distribution systems and/or natural gas infrastructure in Ontario;

h. technical or equipment requirements for the resource and technical or operational experience of the proponent;

i. maturity of the project technology;

j. major project risks, such as delays in implementation, regulatory risks and financial risks and obligations of electricity consumers (such as the financial risk of non-performance by the counterparty), and measures for mitigating those risks; and

k. pricing.

Inclusion of a prequalification phase may be beneficial in many procurements. Where a prequalification phase is used, a number of the above evaluation criteria could be used for purposes of that phase;

iii. require the proponent to agree that, if selected, the proponent will execute a contract on specified terms;

iv. include either a copy of the contract that selected proponents will be required to execute or an adequate summary of the key terms and conditions of that contract – key terms should include term, pricing, critical timelines for being in-service or available, penalties for non-performance by the selected proponent that are appropriate to the nature of the resource being procured, and adequate measures enabling the OPA to assess and verify performance by the selected proponent. Contract terms may be flexible or open to negotiation provided that this does not affect the fairness of the process;

v. except where unreasonable, include a requirement that all proponents provide bid security in an amount commensurate with the project size and development status, and the terms on which that security may be forfeit in whole or in part (such as failure of a selected proponent to enter into a contract with the OPA); and

vi. include mechanisms that ensure that conflicts of interest and collusion between bidders are avoided and that no proponent will have an unfair advantage in relation to the procurement process by reason of preferential access to information or otherwise.

It is expected that the OPA will articulate the following as part of any competitive procurement process:

i. how prospective proponents will be informed that a procurement process has been initiated by the OPA;

ii. mechanisms that will allow prospective proponents to obtain information about procurement opportunities generally as well as about specific procurement initiatives, and how the procurement process operates; and

iii. any registration or other similar conditions that must be met in order for a prospective proponent to participate in the process.

3. Non-competitive Procurement

Non-competitive procurement processes are expected to be used on an exceptional basis. It is expected that the OPA will articulate, as part of such a process:

i. the circumstances under which that process can or will be used;

ii. how the financial risks and obligations of electricity consumers (such as the financial risk of non-performance by the counterparty) that might result from use of that process can be mitigated;

iii. the process by which the OPA will approve and document its decision to use that process; and

iv. an obligation on the OPA in each case to make public its decision to use that process and the reasons justifying that decision.

To the extent that the OPA anticipates that there may be occasions where a competitive process is initially intended but circumstances require a non-competitive process to be used, those circumstances should also be identified.

4. Standard Offer Procurement

A standard offer process may be appropriate for the procurement of specific types of resources. It is expected the OPA to articulate, as part of any such process:

i. the resources to be procured, including as to nature of the resources and the quantity to be procured;

ii. the methodology to be used to determine the standard offer price(s) for each resource;

iii. whether the standard offer will be subject to a ceiling or cap in terms of total participation;

iv. measures that will be used to avoid the "hoarding" of standard offer contracts;

v. how financial risks and obligations of electricity consumers (such as the financial risk of non-performance by the counterparty) that might result from use of the standard offer process can be mitigated; and

vi. other key elements of the standard offer, including:

a. eligibility criteria (including in relation to type of fuel or activity, ownership, location, in-service or availability date, creditworthiness, etc.);

b. security requirements;

c. queuing procedures, if applicable; and

d. key standard offer contract or tariff terms and conditions (including term and default provisions).

Appendix A: Statutory Provisions Regarding the IPSP

Electricity Act, 1998

Integrated power system plan

25.30 (1) Once during each period prescribed by the regulations, or more frequently if required by the Minister or the Board, the OPA shall develop and submit to the Board an integrated power system plan,

(a) that is designed to assist, through effective management of electricity supply, transmission, capacity and demand, the achievement by the Government of Ontario of,

(i) Its goals relating to the adequacy and reliability of electricity supply, including electricity supply from alternative energy sources and renewable energy sources, and

(ii) Its goals relating to demand management; and

(b) That encompasses such other related matters as may be prescribed by the regulations.

Minister's directives

(2) The Minister may issue, and the OPA shall follow in preparing its integrated power system plans, directives that have been approved by the Lieutenant Governor in Council that set out the goals to be achieved during the period to be covered by an integrated power system plan, including goals relating to,

(a) The production of electricity from particular combinations of energy sources and generation technologies;

(b) Increases in generation capacity from alternative energy sources, renewable energy sources or other energy sources;

(c) The phasing-out of coal-fired generation facilities; and

(d) The development and implementation of conservation measures, programs and targets on a system-wide basis or in particular service areas.

Publication

(3) A directive issued under subsection (2) shall be published in *The Ontario Gazette*.

Review of integrated power system plan

(4) The Board shall review each integrated power system plan submitted by the OPA to ensure it complies with any directions issued by the Minister and is economically prudent and cost effective.

Board's powers

(5) After review, the Board may approve a plan or refer it back with comments to the OPA for further consideration and resubmission to the Board.

Deadline for review

(6) The Board shall carry out the review of an integrated power system plan under subsection (4) within such time as the Minister directs.

Regulations, Part II.2

114 (1.3) The Lieutenant Governor in Council may make regulations,

...

(b) governing integrated power system plans and procurement processes;

IPSP Regulation

Period and updating of integrated power system plan

1. For the purpose of section 25.30 of the Act, the OPA,

(a) shall develop and submit an integrated power system plan that covers a period of 20 years from the date of its submission; and

(b) shall develop and submit an update of the plan every three years, which updated plan shall cover a period of 20 years from the date of its submission.

Development of integrated power system plan

2.(1) In developing an integrated power system plan under subsection 25.30 (1) of the Act, the OPA shall follow directives that have been issued by the Minister under subsection 25.30 (2) of the Act and shall do the following:

1. Consult with consumers, distributors, generators, transmitters and other persons who have an interest in the electricity industry in order to ensure that their priorities and views are considered in the development of the plan.
2. Identify and develop innovative strategies to accelerate the implementation of conservation, energy efficiency and demand management measures.
3. Identify opportunities to use natural gas in high efficiency and high value applications in electricity generation.

4. Identify and develop innovative strategies to encourage and facilitate competitive market-based responses and options for meeting overall system needs.
5. Identify measures that will reduce reliance on procurement under section 25.32 of the Act.
6. Identify factors that it must consider in determining that it is advisable to enter into procurement contracts under subsection 25.32 (1) of the Act.
7. Ensure that safety, environmental protection and environmental sustainability are considered in developing the plan.
8. Ensure that for each electricity project recommended in the plan that meets the criteria set out in subsection (2), the plan contains a sound rationale including:
    i. an analysis of the impact on the environment of the electricity project; and
    ii. an analysis of the impact on the environment of a reasonable range of alternatives to the electricity project.

(2) For the purposes of paragraph 8 of subsection (1), the following are the criteria:

1. An environmental assessment of the electricity project under Part II of the *Environmental Assessment Act* must be required.
2. The electricity project, based on the recommended date for completion of the project in the plan, will in the opinion of the OPA require that an application for approval for an undertaking be made under the *Environmental Assessment Act* within five years after the approval of the plan by the Board.

(3) In this section,

"electricity project" means a project that includes one or more of a transmission line, generation facility, transformer station or distribution station;

"environment" means air, land, water, plant life and animal life, including human life and "environmental" has a corresponding meaning.

Publication of plan

3. The OPA shall publish all integrated power system plans that have been approved by the Board under subsection 25.30 (5) of the Act on a publicly accessible website approved by the Board.

Appendix B: The Supply Mix Directive

June 13, 2006

Dr. Jan Carr
Chief Executive Officer
Ontario Power Authority
1600-120 Adelaide Street West
Toronto, Ontario
M5H 1T1

Dear Dr. Carr:

Re: Integrated Power System Plan

As authorized by the Lieutenant Governor in Council under Section 25.30 of the *Electricity Act, 1998*, I am providing direction for the preparation of the Integrated Power System Plan.

The Government directs the OPA to create an Integrated Power System Plan to meet the following goals:

1. The goal for total peak demand reduction from conservation by 2025 is 6,300 MW. The plan should define programs and actions which aim to reduce projected peak demand by 1,350 MW by 2010, and by an additional 3,600 MW by 2025. The reductions of 1,350 MW and 3,600 MW are to be in addition to the 1,350 MW reduction set by the government as a target for achievement by 2007. The plan should assume conservation includes continued use by the government of vehicles such as energy efficiency standards under the *Energy Efficiency Act* and the Building Code, and should include load reduction from initiatives such as: geothermal heating and cooling; solar heating; fuel switching; small scale (10 MW or less) customer-based electricity generation, including small scale natural gas fired co-generation and tri-generation, and including generation encouraged by the recently finalized net metering regulation.

2. Increase Ontario's use of renewable energy such as hydroelectric, wind, solar, and biomass for electricity generation. The plan should assist the government in meeting its target for 2010 of increasing the installed capacity of new renewable

.../cont'd

energy sources by 2,700 MW from the 2003 base, and increase the total capacity of renewable energy sources used in Ontario to 15,700 MW by 2025.

3. Plan for nuclear capacity to meet base-load electricity requirements but limit the installed in-service capacity of nuclear power over the life of the plan to 14,000 MW.

4. Maintain the ability to use natural gas capacity at peak times and pursue applications that allow high efficiency and high value use of the fuel.

5. Plan for coal-fired generation in Ontario to be replaced by cleaner sources in the earliest practical time frame that ensures adequate generating capacity and electricity system reliability in Ontario.

   The OPA should work closely with the IESO to propose a schedule for the replacement of coal-fired generation, taking into account feasible in-service dates for replacement generation and necessary transmission infrastructure.

6. Strengthen the transmission system to:

   - Enable the achievement of the supply mix goals set out in this directive;
   - Facilitate the development and use of renewable energy resources such as wind power, hydroelectric power and biomass in parts of the province where the most significant development opportunities exist;
   - Promote system efficiency and congestion reduction and facilitate the integration of new supply, all in a manner consistent with the need to cost effectively maintain system reliability.

7. The plan should comply with Ontario Regulation 424/04 as revised from time to time.

Yours sincerely,

Dwight Duncan
Minister of Energy

Appendix C: Statutory Provisions Regarding the OPA's Procurement Processes

Electricity Act, 1998

Procurement process for electricity supply, etc.

25.31 (1) The OPA shall develop appropriate procurement processes for managing electricity supply, capacity and demand in accordance with its approved integrated power system plans.

Same

(2) The OPA's procurement processes must provide for simpler procurement processes for electricity supply or capacity to be generated using alternative energy sources or renewable energy sources, or both, where the supply or capacity or the generation facility or unit satisfies the prescribed conditions.

Application for approval

(3) The OPA shall apply to the Board for approval of its proposed procurement processes, and any amendments it proposes.

Board approval

(4) The Board shall review the OPA's proposed procurement processes and any proposed amendments and may approve the procurement processes or refer all or part of them back with comments to the OPA for further consideration and resubmission to the Board.

Deadline for review

(5) The Board shall carry out the review of the proposed procurement processes and any proposed amendments within such time as the Minister directs.

Procurement contracts

25.32 (1) When the OPA considers it advisable, it shall enter into contracts in accordance with procurement processes approved under section 25.31 for the procurement of,

(a) electricity supply or capacity, including supply or capacity to be generated using alternative energy sources, renewable energy sources or both; or

(b) measures that will manage electricity demand or result in the improved management of electricity demand on an on-going or emergency basis.

Contract to comply with regulations

(2) The OPA shall not enter into a procurement contract that does not comply with the regulations.

Resolution of procurement contract disputes

(3) The parties to a procurement contract shall ensure that the contract provides a mechanism to resolve any disputes between them with respect to the contract.

Transition

(4) Despite subsection (2), the Minister may direct the OPA to assume, as of such date as the Minister considers appropriate, responsibility for exercising all powers and performing all duties of the Crown, including powers and duties to be exercised and performed through an agency of the Crown,

(a) under any request for proposals, draft request for proposals, another form of procurement solicitation issued by the Crown or through an agency of the Crown or any other initiative pursued by the Crown or through an agency of the Crown,

(i) that was issued or pursued after January 1, 2004 and before the Board's first approval of the OPA's procurement process under subsection 25.31 (4), and

(ii) that relates to the procurement of electricity supply or capacity or reductions in electricity demand or to measures for the management of electricity demand; and

(b) under any contract entered into by the Crown or an agency of the Crown pursuant to a procurement solicitation or other initiative referred to in clause (a).

Release of the Crown, etc.

(5) As of the day specified in the Minister's direction under subsection (4), the OPA shall assume responsibility in accordance with that subsection and the Crown and any Crown agency referred to in that subsection are released from any and all liabilities and obligations with respect to the matters for which the OPA has assumed responsibility.

Deemed compliance

(6) The following contracts shall be deemed to be procurement contracts entered into in accordance with any integrated power system plan and procurement process approved by the Board:

1. A contract entered into by the OPA following a procurement solicitation or other initiative referred to in clause (4) (a).

2. A contract referred to in clause (4) (b).

Same

(7) The OPA shall enter into any contract following a procurement solicitation or other initiative referred to in clause (4) (a) if directed to do so by the

Minister of Energy, and that contract shall be deemed to be a procurement contract that was entered into in accordance with any integrated power system plan and procurement process approved by the Board.

Regulations, Part II.2

114 (1.3) The Lieutenant Governor in Council may make regulations,

...

(c) prescribing principles to be applied in developing procurement processes and in evaluating proposals for reducing or managing electricity demand or for increasing electricity supply or capacity;

(d) prescribing conditions for the purposes of subsection 25.31 (2);

(e) governing procurement contracts;

Procurement Process Regulation

Assessment of capability of IESO-administered markets

1. The OPA shall not commence the procurement process under section 25.32 of the Act unless it has, in consultation with interested parties, made an assessment of the capability of the IESO-administered markets to, or the likelihood that investment by other persons will,

   (a) meet the need for electricity supply or capacity as identified in an assessment made under section 25.29 of the Act; or

   (b) deliver measures that will manage electricity demand or result in the improved management of electricity demand as described in clause 25.32 (1) (b) of the Act.

Factors for consideration

2. The OPA shall not commence the procurement process under section 25.32 of the Act unless,

   (a) it has considered the factors identified in the integrated power system plan in respect of the advisability of entering into contracts; or

   (b) in the opinion of the OPA, after consultation with the IESO, extraordinary circumstances exist that justify proceeding with a procurement process without consideration of the factors mentioned in clause (a).

Principles in the procurement process

3. In developing procurement processes under section 25.31 of the Act, the OPA shall comply with the following principles:

   1. Procurement processes and selection criteria must be fair and clearly stated and, wherever possible, open and accessible to a broad range of interested bidders.
   2. To the greatest extent possible, the procurement process must be a competitive process.
   3. There must be no conflicts of interest or unfair advantage allowed in the selection process.
   4. To the greatest extent possible, the procurement process must not have an adverse impact outside of the OPA procurement process on investment in electricity supply or capacity or in measures that will manage electricity demand as described in subsection 29.32 (1) of the Act.

No adverse impact of contract

4. The OPA shall ensure that, to the greatest extent possible, any contract it enters into under subsection 25.32 (1) of the Act does not contain any terms or conditions that have an adverse impact on investment by persons who are not parties to such a contract with the OPA in electricity supply or capacity or in measures that will manage electricity demand as described in subsection 29.32 (1) of the Act.

Ontario

ONTARIO ENERGY BOARD

FILE NO.: **EB-2007-0040**

VOLUME: 1

DATE: March 29, 2007

BEFORE:

Gordon Kaiser	Vice Chair and Vice Chair
Pamela Nowina	Vice Chair
Bill Rupert	Member

EB-2007-0040

THE ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act 1998*, S.O.1998, c.15, (Schedule B);

AND IN THE MATTER OF an Application by the Association of Major Power Consumers in Ontario under section 33 of the Electricity Act, 1998 for an Order revoking an amendment to the market rules and referring the amendment back to the Independent Electricity System Operator for further consideration, and for an Order staying the operation of the amendment to the market rules pending completion of the Board's review.

Hearing held at 2300 Yonge Street, 25th Floor,
Toronto, Ontario, on Thursday,
March 29, 2007, commencing at 9:34 a.m.

Volume 1

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our binder. I apologize, it might just be me, but the record, the decision does not bear out the quote that that included.

MR. RUPERT: Mr. Rodger, I was going to mention, I think the page 5 reference, at least as I read it here, didn't refer to the page that was doing what you thought it did. Maybe there is a cross-reference issue in your submissions.

MR. RODGER: I'll certainly check that. Sorry, Mr. Rupert.

MR. KAISER: Why don't you have a look now, and see if you can help us.

MR. RODGER: Mr. Chair, we'll endeavour to get copies during the lunch break.

MR. KAISER: All right. We'll take the lunch break now. We'll come back at 2 o'clock.

--- Recess taken at 12:34 p.m.

--- On resuming at 2:11 p.m.

DECISION:

MR. KAISER: Please be seated.

The Board has decided to issue a decision now on the matter of the relevance of the evidence with respect to the process, rather than deferring it, as Mr. Rodger suggested, in order that we can proceed with the case in a more orderly manner.

We are dealing with an application by AMPCO under section 33(4) of the *Electricity Act* for review of the three times ramp rate market rule amendment. In that

context there has been a discussion and a concern about the scope of the case, and particularly whether evidence regarding the process by which the IESO reached this rule is relevant.

AMPCO submits that the three times ramp rate market rule amendment should be revoked by this Board and referred back to the IESO for stakeholder consultation, based on the following grounds: First, that the process followed by the IESO in the three times ramp rate stakeholder consultation process violated IESO's common-law duty of procedural fairness, by breaching AMPCO's legitimate expectation that the IESO would follow its published stakeholder engagement process and apply its stakeholder engagement principles, and raising a reasonable apprehension of bias that the IESO favoured the interests of generators; secondly, that the integrity of the statutorily-mandated consultation process has been undermined. They say this is inconsistent with the purposes of the *Electricity Act* and unjustly discriminates against Ontario consumers in favour of Ontario generators.

They also allege certain substantive failures, as well, which are not at issue in the proceeding this morning.

Accordingly, AMPCO argues that the materials produced by IESO relating to procedural matters are relevant both to the issue of procedural fairness and also the substantive issues.

The starting point in this discussion is section 33(9)

of the *Electricity Act*. It has been referred to by virtually everyone this morning. It provides that:

> "If, on completion of its review, the Board finds that the amendment is inconsistent with the purposes of this *Act*, or unjustly discriminates against or in favour of a market participant or a class of market participants, then the Board shall make an order revoking the amendment on the date specified by the Board and referring the amendment back to the IESO for further consideration."

AMPCO argues that all of the IESO materials are relevant because they demonstrate that the IESO failed to follow procedural fairness in developing the amendment. According to AMPCO, the lack of procedural fairness demonstrates that the amendment unjustly discriminates against its members in favour of generators.

In other words, AMPCO argues that it has rights of natural justice in IESO rule-making and that those rights should be enforced by the Board in the market review amendment process.

All of the other parties appearing before us this morning state that this is an incorrect interpretation of section 33(9), because it equates the term "unjustly discriminates" with a violation of the rules of natural justice and it equates the Board's review process with a judicial review application.

They argue that the purpose of the Board's review in a

market review amendment should be aimed at economic efficiency and not natural justice.

They say that the OEB should be reviewing an amendment to the IESO rules and not the IESO stakeholdering process; that the scope of the Board's review should be aimed at the rule itself, and the impact of that rule, not the process by which the amendment was made.

In other words, it's argued before us that the issue is whether the rule is unjustly discriminatory. The Board agrees with that position.

Sections 19(1) and 20 of the *OEB Act*, read together, provide that the Board has general authority to determine any question of law or fact arising in any matter before it except where that authority is limited by statutory provision to the contrary.

In the case of a market rule amendment, another statutory provision does limit the Board's jurisdiction. Section 33(9) of the *Electricity Act* specifically sets out certain grounds on which the Board may make an order.

Accordingly, we find that section 33(9) of the *Electricity Act* is a jurisdiction-limiting provision, not another jurisdiction-granting provision. That is, with respect to a market rule amendment, the Board's jurisdiction is not as broad as suggested by section 20 of the *OEB Act*, but limited by section 33(9) of the *Electricity Act*.

In this regard, the Board has also considered the submissions of various parties, and agrees, that the 60-day

time limit for disposing of this review is consistent with the conclusion that the Board's scope of review is limited to the criteria set out in section 33(9).

The legislature can be taken as having known that an exhaustive review of the process would render it impossible to meet these timelines.

We then come to what can be seen as a second and distinct issue. That is whether there is a common-law principle of administrative law that the IESO has violated in the course of this market rule amendment process which yields a separate and distinct remedy.

The IESO says the common-law principles of administrative law do not assist AMPCO in extending the jurisdiction of the Board to review the details of the stakeholdering process. They say that the IESO is a statutory corporation whose affairs are managed and supervised by an independent board of directors, and the functions carried out by the IESO under the review at issue in this proceeding is a rule-making function and is essentially a legislative function.

They rely upon the Supreme Court of Canada's 1980 decision in the Inuit Tapirisat as support for the proposition that in legislative functions these rules do not apply.

AMPCO takes a different view and it relies upon the Supreme Court of Canada 1990 decision in Baker, as well as the Divisional Court decision in Bezaire.

The aspects of the decision that AMPCO relies upon can

be found at pages 15 and 14, where the Court stated that one of the criteria that must be looked at in determining whether the rules of natural justice apply to a process is whether the parties had a legitimate expectation that those rules would be followed. The Court states, in part:

> "Fourth, the legitimate expectations of the person challenging the decision may also determine what procedures the duty of fairness requires in given circumstance."

They go on to say:

> "This doctrine as applied in Canada is based on the principle that the circumstances affecting procedural fairness take into account the promises or regular practices of administrative decision-makers and it would generally be unfair for them to act in contravention of representations as to procedure or to backtrack on substantive promises without according significant procedural rights."

The Court also noted that another factor to be considered in determining the nature and extent of the duty of fairness that's owed to the parties is the importance of the decision to individuals involved.

As has been pointed out, there's no question that there's a significant amount of money involved in this decision; it's an important decision. With respect to the expectations of the parties, there is a provision in section 13.2 of the *Electricity Act* requiring the IESO to

establish processes by which consumers, distributors and generators may provide advice. AMPCO makes the point that a framework was established to govern the process by which these rules would be amended and implemented. They say that this procedure, despite the expectation they were entitled to, has not been followed.

That may or may not be the case, but this Panel is of the view that that is not a matter for our consideration. Mr. Vegh in his submissions questioned whether the Board should be a parallel Divisional Court. We don't think it should be.

IESO may or may not have followed the rules of natural justice. And they may or may not have been required to do so based upon the different authorities that have been cited by the different parties. But that, we believe, is a matter to be determined by the Divisional Court, not the Ontario Energy Board.

Mr. Rodger did refer us to a decision of this Board on September 20th, 2005. That appears at tab 11 of Ms. DeMarco's brief. I'm reading in part:

> "The Board concludes that stakeholder concerns have been substantially met. The true test will, however, be the experience of stakeholders in the new process. Stakeholders and the Board will have opportunities to review how well the process works over time as they are implemented. The Board therefore approves the IESO proposals on its stakeholdering process. It should be noted,

however, that this approval relates to the processes that the IESO has proposed. It does not change the Board's obligation to review IESO programs that have implications for IESO fees, expenses and revenue requirements, even when these programs have been subjected to the IESO stakeholdering process."

Mr. Rodger's submission was that having approved the stakeholdering process it was incumbent upon the Board to follow through and police, if you will, the rule-making process.

We differ on that. The two are distinct functions. The review at question is a judicial review and best reserved for the courts.

That leads us to the Order requested. Pursuant to this decision, the Board will order that any evidence relating to the stakeholdering process be struck. That would include Mr. Rodger's submission of March 26th. If the parties are unable to agree on what evidence is to be excluded or not excluded, the Board may be spoken to.

That completes the Board's ruling in this matter.

PROCEDURAL MATTERS:

Mr. Rodger and Mr. Mark, we were going to suggest, subject to your convenience, that you may want to adjourn for the rest of the day and regroup in light of that.

MR. MARK: It probably makes sense.

MR. KAISER: Unless there be some debate and discussion as to what evidence is to be struck and what

evidence is not to be struck.

MR. MARK: I think we should adjourn. I think Mr. Rodger and counsel should discuss a number of issues that flow out of this in terms of what evidence is in or out and what procedures may be most appropriate to conclude the evidentiary portion of the hearing in light of your ruling.

MR. KAISER: Mr. Rodger?

MR. RODGER: May I just have a moment?

MR. KAISER: Yes.

MR. RODGER: Yes, Mr. Chairman, we would support that; adjourn the proceedings for today, and we'll speak with counsel for the IESO and others and perhaps resume in the morning with the path ahead.

MR. KAISER: All right. Thank you, gentlemen, ladies. 9:30 tomorrow.

--- Whereupon the hearing adjourned at 2:27 p.m.