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SUBMISSION TO THE ONTARIO ENERGY BOARD

RE: EB-2007-0707

Ontario Power Authority (OPA) Application in Respect of the Integrated Power System Plan (IPSP)

GENERAL COMMENTS

The Ontario Energy Board (Board) has been given the monumental task of reviewing the proposed Integrated Power System Plan (IPSP), and the thousands of pages of supporting documentation, consultants' reports and stakeholder input for two distinct purposes. The review is to determine whether the IPSP complies with Ministerial directives, and whether the Power Plan meets the requirements of economic prudence and cost effectiveness.

The CAE Alliance believes that the proposed IPSP fails to meet the necessary criteria in both areas. Although we will provide supporting information for our concerns under the respective issues, there are some aspects of non-compliance that are more general in nature.

1. Compliance with Ministerial Directive - Reliability and Adequacy of Electricity Supply

The Ministerial Directive of June 13, 2006, directs the Ontario Power Authority (OPA) to comply with Ontario Regulation 424/04. Both the Ministerial Directive and the Regulation reference development of an IPSP according to the Electricity Act, 1998, as amended, Section 25.30, which is " designed to assist, through effective management of electricity supply, transmission, capacity and demand, the achievement by the Government of Ontario of, its goals relating to the adequacy and reliability of electricity supply..." The goals of the Government of Ontario are also stated in the Ministry of Energy Statement of Environmental Values, under the Environmental Bill of Rights. The express mandate is "to ensure that Ontarians have access to safe, reliable and environmentally sustainable energy supplies at competitive prices**".**

The CAE Alliance believes that there are points of contradiction between legislative demands in respect of the power plan for Ontario. The CAE Alliance maintains that the government goals expressed above, and the Ministry of Energy mandate noted above are of highest priority in the preparation of the IPSP. However, the OPA has chosen to implement the Ministerial Directive in ways that actually imperils the ability to provide adequate, reliable and affordable power. The OPA has chosen to consider the Ministerial Directive as first priority in power planning, rather than affordable and reliable power for Ontarians.

The OPA states that "system reliability cannot be compromised at any time during the plan. ... This requires a sufficient level of supply and conservation at all times to meet demands with confidence. ... The system must be designed to withstand various contingencies ... System reliability is considered non-negotiable." (Sustainability Discussion Paper)

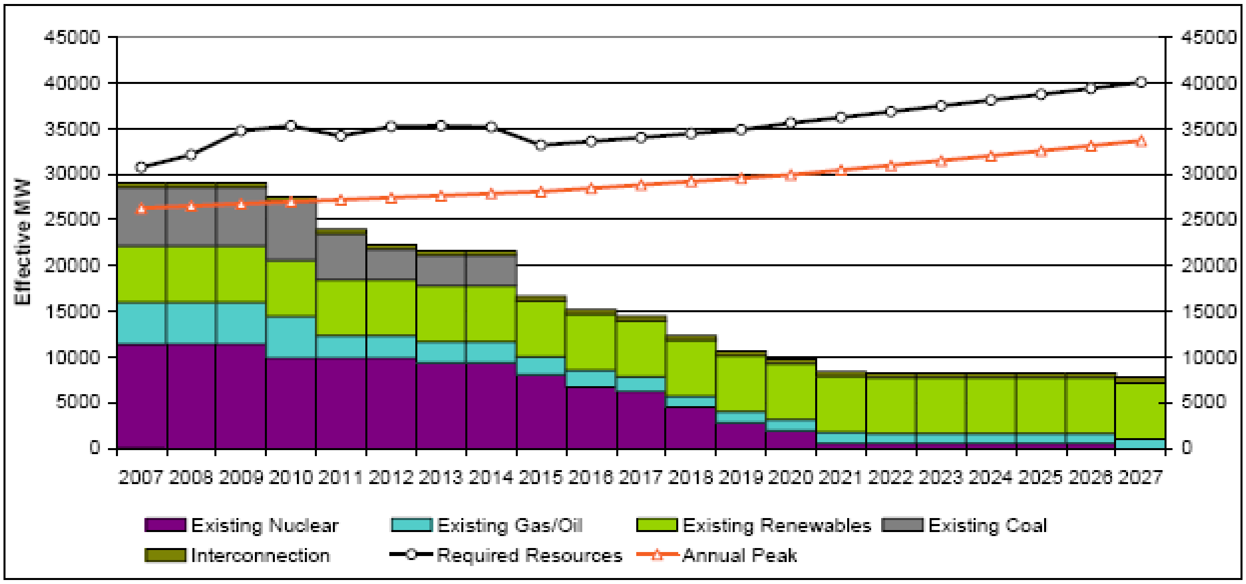
The CAE Alliance maintains that the IPSP does not ensure reliable and adequate supply of electricity to Ontario consumers. Concerns include:

(i) Resource Uncertainties and Contingencies
(ii) Over-reliance on Natural Gas-fired Generation
(iii) Insufficient Load Following Resources and Dispatchability

(i) Resource Uncertainties and Contingencies

♦ The following chart graphically displays the significant amount of new or refurbished electricity generation resources that will be required over the 20 year period. The OPA notes that there will be a "tight resource balance" and that "successful implementation of a large number of individual projects is essential for adequacy". (Integration Discussion Paper, November, 2006)

Figure 1: Modification of Figure 1 in Exhibit D-3-1 "Contribution of Existing Resources Towards Resource Requirements (Effective MW)



Source: OPA

(EB-2007-0707 Exhibit I Tab 38 Schedule 31 Page 2 of 3 Filed: June 18, 2008)

♦ Too many uncertainties regarding resource implementation threaten the adequate supply of electricity. The OPA has not alleviated these concerns addressed by way of Interrogatories. Throughout the Interrogatory responses the phrase "the IPSP is sufficiently robust to accommodate these possibilities" is continually repeated to address resource uncertainties. How many contingencies can be lumped under this umbrella before the Plan begins to crumble?

♦ The "robustness" of the Plan is discussed using various options, including higher load growth; higher conservation; no development of northern renewables; and no refurbishment of Pickering B. (Exhibit G, Tab 1, Schedule 1) The solution to shortfalls is expressed by implementing higher natural gas use and higher imports. However, the OPA does not assess cumulative impacts of any combination of resource inadequacy, for example, higher lower growth in conjunction with no northern development of renewables.

♦ The OPA notes that lower nuclear capacity could increase natural gas production by 5-23 TWh. How much additional production would be required from the potential impact of lower conservation achievement?

♦ The OPA indicates that economically feasible conservation takes priority over supply resources in meeting resource requirements. It is therefore imperative to system security that these resources materialize. Inaccurate or overly optimistic assessment of achievable targets will lead to a shortfall of generating capacity. When questioned regarding the mitigation measures in event of less than anticipated success in CDM achievement, the OPA advised that " The IPSP is a flexible Plan that can accommodate various levels of Conservation performance." (Response to AMPCO) However, this does not conform with OPA statements that the target Conservation/Demand Management is "the most ambitious undertaken anywhere", and "…it will be a challenge for Ontario to deliver the near-term amount of CDM included in the plan." (OPA) According to Peter Love, Chief Conservation Officer, the amount of CDM planned is "very aggressive, extremely aggressive, more than what California has been able to achieve".

♦ The Plan includes imports as a contingency tool for resource inadequacy or shortfall. However, the OPA did not evaluate surrounding jurisdictions that provide power to Ontario to determine future power constraints in neighbouring jurisdictions. "For the purpose of this Plan, the focus is on Ontario's electricity needs and does not address potential market demand involving interconnected jurisdictions. ... "Estimating imports requires assumptions about specific conditions within neighbouring markets over long periods of time, resulting in a considerable margin of uncertainty around specific results."

♦ In the original Supply Mix Advice and Recommendations, the OPA noted that much of resource planning is contingent on best case scenarios in terms of timing, fuel costs and variables outside of the control of the OPA. The IPSP contains even more variables, higher fuel costs and higher new resource requirements.

♦ It has been noted that the OPA relies on models which are themselves based on information that may be obsolete or no longer relevant. This increases risks of energy shortfalls in future.

♦ Uncertainties and contingencies equal risk. The risks associated with resource supply implementation are determined using models and casino style risk assessment to determine the potential for overall resource inadequacies. The OPA has not made a valid assessment of real risk potential using present fuel costs, construction material cost escalation; past experiences, such as nuclear cost overruns in Ontario, nor future availability of plant or transmission components.

Some of these identified risks include:

Conservation - "There is a risk associated with conservation and demand management in both the timing and the levels they represent. Failure to meet the targeted levels at the prescribed time would lead to higher levels of demand than identified …" (IESO – 18 Month Outlook, June 22, 2007)

Nuclear - Nuclear units will reach end of life between 2013 and 2022. "Availability is lowest between 2016 and 2020 when a number of units are simultaneously on refurbishment outages." … For purposes of overall adequacy, it will be especially critical to manage and maximize nuclear availability during this period." (OPA Discussion Paper - Integration)
"…the availability of skilled labour, long lead time for equipment and critical material resources can adversely impact scheduled completion dates and cost. …" (OPA)

Renewable Resources - Wind development between 2015 and 2019 is dependent upon transmission enhancements in the Bruce Peninsula area. "Bioenergy has perhaps the greatest degree of uncertainty as to potential, cost and feasibility." (OPA – Discussion Papers, November, 2006)
Even if all renewable energy hoped for is in place by 2015, it is not possible for these resources to produce the proposed additional 12-15 TWh of power required from them.

Natural Gas - “While it is impossible to quantify all of the risks at this point, the price and supply risk around gas as a generation source has grown significantly.” (OPA) This was an assessment made late in 2005. The concerns with natural gas have not been alleviated, but have escalated.

"Of the planned resources to be procured, the gas-fired generation resources may face acquisition risks concerning: timing of approvals; availability of project components; and availability of construction resources...." (EB-2007-0707 Exhibit 1, Tab 1, Schedule 16, page 2 of2)

Transmission - “Without new transmission facilities, the IESO will be forced to operate existing facilities near their maximum capabilities, with little margin for unexpected events and requiring complex arrangements to do routine maintenance on critical facilities. A number of local transmission or generation initiatives are also needed in areas throughout Ontario.” (IESO, The Ontario Reliability Outlook, March, 2007)

“The IESO remains concerned about the uncertainty around the length of approvals process affecting generation and transmission projects. … The situation is particularly troublesome in the case of new transmission. … there will continue to be a risk that transmission will not be available when it is required.” (IESO, The Ontario Reliability Outlook, March, 2007)

More recently, the OPA notes that "All transmission projects in the Plan are subject to approvals risks and could experience delays." (Response to the PWU)

Imports - “Longer-term Ontario may not be able to continue to rely on the same level of support from its interconnected neighbours as it has received in the past. Surrounding jurisdictions … are beginning to face the prospect of declining supply margins. … Although the benefits of being interconnected continue to exist, this decline will serve to reduce Ontario’s confidence in imports.” (IESO, The Ontario Reliability Outlook, March, 2007)

These are valid concerns that are increasing in probability.

While the OPA acknowledges risks and concerns associated with near and mid term planning, (“less than anticipated success in capturing conservation potential, harvesting domestic renewable resource potential, less than expected nuclear performance, higher than anticipated load growth and the potential retirement of existing non-utility generation resources”), the “risk around the implementation and performance of new resources is managed by the timing of coal replacement and by imports.” As coal-fired generation is phased out, and beyond, natural gas becomes the "swing fuel" to alleviate these concerns.

(ii) Over-reliance on Natural Gas-fired Generation as it impacts overall system reliability

The CAE Alliance believes that the IPSP places an unhealthy and imprudent reliance on natural gas in a variety of circumstances. Natural gas fired generation will form a critical component of the Plan, but in doing so creates a fatal flaw. As we will indicate in the next section, natural gas cannot perform the quality of load following expected of it as replacement for coal-fired generation. The cost and supply concerns which will be discussed in later sections of this information caution against reliance on natural gas-fired generation.

Throughout the IPSP information, and in answer to interrogatories, the OPA has addressed contingencies and potential problems by indicating that natural gas-fired generation will be used to supply shortfalls. However, the OPA has not provided any contingency plan for the significant use of natural gas should gas-fired generation prove too costly or unreliable as a result of gas supply constraints. The OPA has no contingency plan for a critical component of the plan which in itself is subject to significant risk.

♦ The IPSP proposes utilizing natural gas as the "finger in the dyke", suggesting that more natural gas generation will be used:

- for coal replacement;

- if conservation goals are not met;

- if power demand is higher than planned;

- "In general, natural gas resources and imports are expected to provide swing capability to complement the variability of other types of resources." (Response to Board)

- "If wind generation is less than projected by 2020, it is expected that the energy shortfall would be made up by higher production from gas-fired resources and a higher amount of economic imports."(Response to Board)

- if renewable energy supplies are insufficient to meet demand;

- as interim replacement for nuclear if the Pickering B units are not refurbished;

- "Given the timing of the nuclear additions to the Plan (starting in 2018), it is premature to develop a specific and detailed mitigation plan. Mitigation measures may include operating with reduced margins, or building short lead time gas-fired generation and arranging short-term firm imports." (Response to Board)

- if nuclear units run at less than anticipated capacity - "Reductions in nuclear production in the order of 5 TWh to 23 TWh per year could be compensated over the mid-to-long-term by a combination of higher utilization of existing, committed and planned natural gas-fired resources, reduced exports, increased imports and generally greater reliance on planning margins." (Response to Board)

- in case of surplus baseload power - if nuclear units are shut down gas generation would provide service until nuclear units are brought back into service (72 hours)

- "If conditions warrant" the development of new gas-fired generation in the Northwest or the conversion of Atikokan GS and/or Thunder Bay GS to natural gas operation

- to compensate for intermittency of wind production

- specific gas-fired generation facilities as substitutes for transmission reinforcement

- in southern Ontario to address system reliability. The location of these resources in constrained local areas avoids the land use requirements that would have been needed for transmission rights-of-way

♦ "Under the IPSP, natural gas-fired generation capacity in Ontario grows by 140 percent, from 5,029 MW in 2007 to 12,082 MW in 2015. The potential peak requirement for natural gas for power generation increases by about 1,250 MMcf/day, from 522 MMcf/day in 2007 to 1,767 MMcf/day in 2015." (EB-2007-0707- Exhibit 1-12-34 Attachment 1)

♦ The potential maximum natural gas requirement for electricity generation will increase from 1,021 MMcf/day in 2007 to 2,266 MMcf/day in 2015. (EB-2007-0707- Exhibit 1-12-34 Attachment 1)

♦ About 10% of natural gas currently consumed in Ontario is used to generate electricity. This is expected to double and reach peak use "during the 2016-2020 period" which, according to the OPA is when gas prices will be high due to depleting of resources in the Alberta Basin.

♦ "The capacity additions included in the IPSP for the years after 2014 vary considerably from case to case. Table 22 shows the installed gas-fired generation capacity and potential gas use for Case 1B (Base Case, Pickering Not Refurbished), the case with the most gas-fired capacity additions and the highest potential peak gas requirement. Installed gas-fired generation capacity and the maximum gas requirement both peak in 2019. An additional 700 MW of unspecified capacity added between 2014 and 2019 is modeled as a mix of simple cycle and combined cycle generating capacity. The potential peak gas requirement for electricity generation continues to increase after 2019 as 125 MW of new combined cycle generation replaces the dual-fired Lennox plant." (EB 2007-0707-Exhibit G, Tab 1, Schedule 1)

♦ "Under the assumptions of Case 2B (High Demand, Pickering Not Refurbished), gas use for power generation doubles between 2007 and the 2016-2020 period. The increase over the same period in Case 1A (Base Case, Pickering Refurbished) is 55 percent." (EB 2007-0707-Exhibit G, Tab 1, Schedule 1)

Table 22: Gas-Fired Generation Capacity and Potential Gas Use (Case 1B)

	Installed Capacity (MW)			
	2015	2019	2023	2027
Lennox	2,100	2,100	0	0
NUG	1,517	1,517	1,386	1,517
CHP	1,322	1,322	1,322	1,322
Combined Cycle	5,793	5,918	5,918	6,043
Simple Cycle	1,350	1,925	1,925	1,925
Total	12,082	12,782	10,551	10,807
Maximum Gas Use (MMcf/day)	2,266	2,410	1,887	1,932
Peak Requirement (MMcf/day)	1,767	1,911	1,887	1,932

♦ It is important to note that this chart does not demonstrate the cumulative impacts on gas use if nuclear capacity is lower than anticipated (an additional 5-23 TWh); if there is higher load growth than planned (an additional 10 TWh); plus the potential for "additional “unspecified” gas-fired generation is also required beginning in 2020 to supplement wind in the south" if the northern renewables do not materialize. (EB 2007-0707-Exhibit G, Tab 1, Schedule 1)
A combination of these factors alone could increase gas-fired production requirements by an additional 15-33 +TWh - 20% of Ontario's annual demand! It is not unreasonable to assume this could materialize.

♦ The consultant's report to the OPA notes that "<u>Most</u> of the natural gas transmission, storage, and distribution facilities needed for the <u>4,300 MW</u> of committed gas-fired capacity included in the IPSP are currently available or in construction." (emphasis added) However, as noted on the chart above, installed gas capacity is expected to grow from 5,029 MW in 2007 to 12,782 MW in 2019. This is an increase of 7,753 MW. (Even with the reduction of Lennox, 2100 MW, there would still not be sufficient infrastructure to accommodate the remaining 3,450 MW of gas-fired capacity.

♦ Natural gas use is estimated using the following heat rates: Combined cycle 7,150 MMBtu/KWh; Simple cycle 9,141 MMBtu/Kwh. (EB-2007-0707- Exhibit 1-12-34 Attachment 1) This represents 100% load condition. Heat rate will increase as load condition decreases. Likewise, "the OPA assumed a heat rate for the Nanticoke gas conversion scenario of 10,600-11,000 Btu/kWh. ... The heat rate assumed for the simple cycle plants at Dawn and Southwest GTA is 9,600 Btu/kWh. ... The effects of plant ageing, part load operation and starts and stops are not included in the economic analysis for all scenarios. ... The effects of inlet temperature on combustion turbine heat rates and maintenance cost are not included in the economic analysis." (emphasis added - EB 2007-0707-Exhibit 1, Tab 32)

♦ "Natural gas-fired generating plants typically require relatively large quantities of gas and high gas delivery pressures." (EB-2007-0707- Exhibit 1-12-34 Attachment 1) In spite of this, the OPA has refused to confirm whether the gas generating facilities under development or procurement in Ontario have contracted for firm gas delivery.

Conclusion
Natural gas-fired generation will be expected to fulfill a significant part of critical load following and load balancing requirements in Ontario. This necessitates reliance on (primarily) private power producers to generate when required for as long or short as required - something new to the Ontario system. Also, the dispatch order dictates that natural gas generation will set market price the majority of the time. With due respect to these private power marketers, we are leaving the Ontario system vulnerable to outside influences.

More specific concerns regarding natural gas-fired generation are answered under Issues 15-19, Pages 28 and following.

(iii) Insufficient Load Following Resources and Dispatchability

♦ According to the OPA, "The existing coal-fired generation resources provide a number of important functions which contribute to the adequacy and reliability of the Ontario electricity system. These resources provide operating flexibility, are dispatchable and are able to respond quickly to various system requirements as and when needed under the dispatch control of the IESO. Traditionally, the coal-fired resources have been utilized to meet changing load demand, to meet supply needs when other supply resources are not available, and to balance load and demand at all times. ... During morning pick-up periods, typical load changes of about 60 to 70 MW per minute occur. These can total more than 3,000 MW an hour, with sustained periods of increase or decrease lasting for up to four hours or more. The reverse typically happens during evening hours when load reductions are required. Throughout the day, there can also be load changes that occur during five-minute intervals. The coal-fired units are currently under the dispatch control of the IESO on a five minute basis, and play an important role in responding to these load changes given their ability to meet different load-following requirements. In particular, these units typically have load-following capability from minimum load up to maximum load, equivalent to the upper 80% of each unit's capacity range." (EB-2007-0707 Exhibit I Tab 1 Schedule 33)
Replacement for these critical requirements are an important element of system reliability.

♦ Questions/concerns were directed to the OPA regarding the characteristics of coal-fired replacement, as noted above, including load following, the "critical component" of providing responsive operating reserve, support during voltage disturbances and reactive support. The OPA responded to these important queries by indicating that "The IESO has recently completed an Operability Review of the IPSP ... which concluded:

The IESO has assessed the operability of the IPSP and concluded that it provides sufficient flexibility to meet future system needs. Current market mechanisms and control actions will allow the IESO to reliably operate the system described in the IPSP."

However, this IESO report also states that "The IESO's analysis was performed using production data provided by the OPA. As such, the data reflects the many assumptions used in the IPSP. The IESO did not modify any IPSP assumptions. ... The IESO was required to make certain assumptions to accurately interpret the simulated data and produce meaningful operating conditions:

• Existing generation resources were assumed to have ramping and operating characteristics similar to those they currently exhibit in the IESO- administered markets.

• Generation resources not yet in service were assumed to have ramping and operating characteristics similar to existing resources of the same technology type. Some operating parameters such as minimum load point were adjusted in proportion to nameplate capacity. ..." (www.ieso.ca/imoweb/pubs/ircp/IESO-Operability_Review_of_IPSP.pdf)

The CAE Alliance asserts that this answer sidesteps the questions and that critical questions raised regarding reliability remain unanswered.

♦ Natural gas-fired generation will be required for quick dispatchability and optimum load following. This need will increase as more wind power is added to the system. The coincidence of the tendency of wind to drop off during morning and evening with the rapid increase/decrease of load will increase the need for these generating characteristics. However, there are concerns and implications for natural gas-fired units that the OPA has not addressed.

Combined cycle gas plants can load follow provided that the load swing is not too great. There are a lot of problems in a combined cycle mode operation with the gas turbines required to load follow. The efficiency of a gas turbine at part load is terrible and frequent starts on a daily or weekly basis increases outages and maintenance costs. Higher fuel use, lower efficiency and wear impact on gas facilities will result in higher outage rates, higher emissions and higher costs.

The OPA has not sought independent expert assessment of whether gas-fired generators can reliably respond to sudden load changes on a practical day by day basis.

♦ The OPA indicates that ""Both gas-fired and coal-fired generation facilities are flexible and fairly responsive resources to meet various load-following requirements. The main differences are associated with their load-following capability relative to their capacity range, with coal-fired units generally covering a larger unit capacity range compared to gas-fired units." However, the OPA has not assessed the practical realities of this on a day to day operating basis.

♦ The addition of intermittent renewable resources (wind and solar) has, according to the OPA, "Potential implications for grid reliability which includes the requirement for sufficient load following capability, as well as the requirement to mitigate impacts of wind variability on power quality and voltage performance. Load following capability can be supported by more flexible generation such as simple cycle gas-fired generators..."

Coal-fired generation currently fulfills this function, in conjunction with hydroelectric resources. It does not appear that the OPA has determined when single cycle gas units will be required. It is presumed, from the information provided in the IPSP, that single cycle units were selected for peak hours and peak seasons. The above statement would indicate that simple cycle gas-fired generators would operate on a daily basis to compensate for the variability of wind and solar resources.

♦ "The first five years of the analysis, from 2010-2016, are the critical period, during which there is a profound transformation of the resource mix. During this period all of the coal-fired plants will be replaced with gas-fired units, hydroelectric, wind and conservation programs. In addition, a number of nuclear units are expected to be removed from operation for refurbishment. Over the 2010-2014 period, five of 40 days studied (12.5%) showed load following shortfalls, though all were successfully resolved by applying the unit commitment, curtailing exports and constraining-off dispatchable loads." ... during the period 2017-2026 " ...the frequency of critical days with seemingly insufficient load following increased to 10 of 48 days (20.8%). With the increase, several days required more actions then were needed in the previous period to overcome shortfalls. In addition to such actions as unit commitment, curtailment of exports, and constraining off of dispatchable loads, further imports and outage management were needed to resolve shortfalls." (www.ieso.ca/imoweb/pubs/ircp/IESO-Operability_Review_of_IPSP.pdf)

If there are shortfalls with the best case scenario (all CDM, all new installations of resources in place and no premature reduction in nuclear capability), what is the impact of worst case scenario?
(Load following concerns are discussed further at Issue 20, Replacement for Coal-fired Generation.

♦ The IPSP does not address whether IESO has dispatch control of private generators. With due respect to current market participants, it does not appear that OPA has taken into consideration the potential for generator unwillingness or inability to provide critical generation at peak times. IESO notes that "Where unit commitment and dispatch of dispatchable loads was unlikely to resolve hourly shortfalls in load following capability, other actions were evaluated for effectiveness. Generally these events occurred in the summer, during periods of high demand and challenging operating conditions which typically included periods of operating reserve shortfalls. These types of conditions send market price signals that cause market participants to reschedule planned outages and elect not to export. All shortfalls in hourly load following that remained after using the unit commitment process and the dispatch of dispatchable loads could be resolved through a combination of outage management (provided to the IESO through the OPA's hourly availability schedules) and curtailment of exports (provided through the hourly export schedules). It is expected that should such shortfalls actually develop, normal market price signals would be sufficient to drive these outcomes without intervention by the IESO." (www.ieso.ca/imoweb/pubs/ircp/IESO-Operability_Review_of_IPSP.pdf)

♦ As the public is not privy to contracts with merchant generators, we do not have the confidence that IESO can rely on private generators to supply power when required. For example, at least two of the new power facilities (St. Clair Energy and Greenfield Energy - a total of 1,570 MW - in the Sarnia Lambton area) could export power at profit into the U.S. market without impact to minimum monthly support payments guaranteed by the OPA. For purposes of determining payments to these generators, they are deemed "not generating" when exporting power. (OPA) We are unaware of any contractual obligations to generate when needed, nor what "intervention" might be required by the IESO. With public utility providing power on demand, this problem has not previously arisen.

♦ The OPA has factored "500 MW import in all years (*upon coal closure*) which offsets an assumed planned outage to a 500 MW gas-fired generator. (Under the market rules, a generator is required to arrange a short-term firm purchase during the period of a unit outage if that outage would have otherwise been cancelled by the IESO for reliability reasons.)" Presumably gas-fired generators will plan outages outside of peak seasons. If the plan was sufficiently robust, these imports would not be required. Also, there are a number of gas-fired power plants proposed for Ontario - 7,000-9,000 MW worth. It is reasonable to expect multiple unit outages, resulting in insufficient power to address the resources that would be unavailable.

2. Economic Prudence and Cost Effectiveness

This is a precarious time for the Ontario economy. Energy costs are already a component of major job losses in the province. The higher electricity rates that will occur as a result of the implementation of this IPSP will be the knock-out punch to our economy, causing a situation that we will not recovery from. We have not finished paying the $20 billion bill from current energy resources, we have not even begun to pay for these proposed changes and we already cannot afford it!

The OPA has indicated that "electricity plays such an important role in our economic health", and "Over the next decade Ontario faces a major transformation of its power system. The plans and decisions we make now will have a profound impact for many decades to come." (Discussion Paper Supply Resources) "Higher electricity prices not only take a bite out of the consumer's budget, but also affect the competitiveness of business." (CERI Report to OPA)

In spite of this statement, the IPSP is flawed in determination of costs to consumers in all sectors - residential; commercial and small business; the municipal/educational/health care (MUSH); the agricultural; and the industrial ratepayers. The OPA has not assessed the cost impacts on the Ontario economy.

♦ The Board however, indicates that the review of economic prudence and cost effectiveness of the IPSP "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." (Board Report, Pages 8, 9) Further, the Board advises that section 1 of the OEB Act informs the Board in the exercise of that mandate (Decision with Reasons, in respect of the Issues List), namely, the protection of the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service. ... "

♦ When questioned as to the OPA's criteria for measuring or determining "affordable", the OPA responded that "the concept of affordability is judged in the context of the current situation and any changes that may arise from the implementation of the Plan. The OPA conducted a cost to-customer analysis as part of the IPSP ... This analysis concluded that household consumption will be reduced as a result of achieving the IPSP's Conservation goals and that a representative household electricity bill will decline over the period of the IPSP. The impact of the IPSP for an individual customer will depend on consumption patterns, levels of Conservation, time of use, local service terms and conditions, and any contracts that a customer may enter into for service. (Response to the PWU)

This response addresses only residential consumer costs, not commercial or industrial. Further, as noted in the section below on the impact of smart meters on residential consumers, costs can only escalate. The household use that can be load shifted is limited, and those items that cannot be will be used at higher prices throughout the day. Reduction in residential use of electricity assumes a degree of fuel switching, the upfront costs of which will likely not be recovered.

♦ "Affordable" is defined as "to manage to bear without serious detriment; to be able to bear the cost of" (Merriam-Webster on-line dictionary). The IPSP certainly does not accurately or completely address the issue of affordability of power.

The following information demonstrates some of the cost impacts that the OPA has not fully evaluated which we believe represent financial cost implications of the IPSP that will affect provincial electricity prices, rates, and the economic health of Ontario in the long and short term. They include:

(i) Smart Meter Impact - Small Business and Residential Use
(ii) Impact of Natural gas-fired Generation on Market Price
(iii) OPA Cost Assessment of the Plan
(iv) Costs not included in the IPSP

(i) <u>Smart Meter Impact - Small Business Use</u>

Time-of-Use pricing diagrams

The Summer weekdays	Weekends and Holidays	The Winter weekdays
The highest energy prices occur over the afternoon, largely due to greater air-conditioning use. That's why the on-peak rate is from 11 a.m. to 5 p.m.	Demand and electricity prices are lower on weekends and holidays – as well as overnight – so these periods are all off-peak.	Energy prices peak twice – in the early morning and in the evening – mainly due to space heating, plus increased lighting and appliance use.

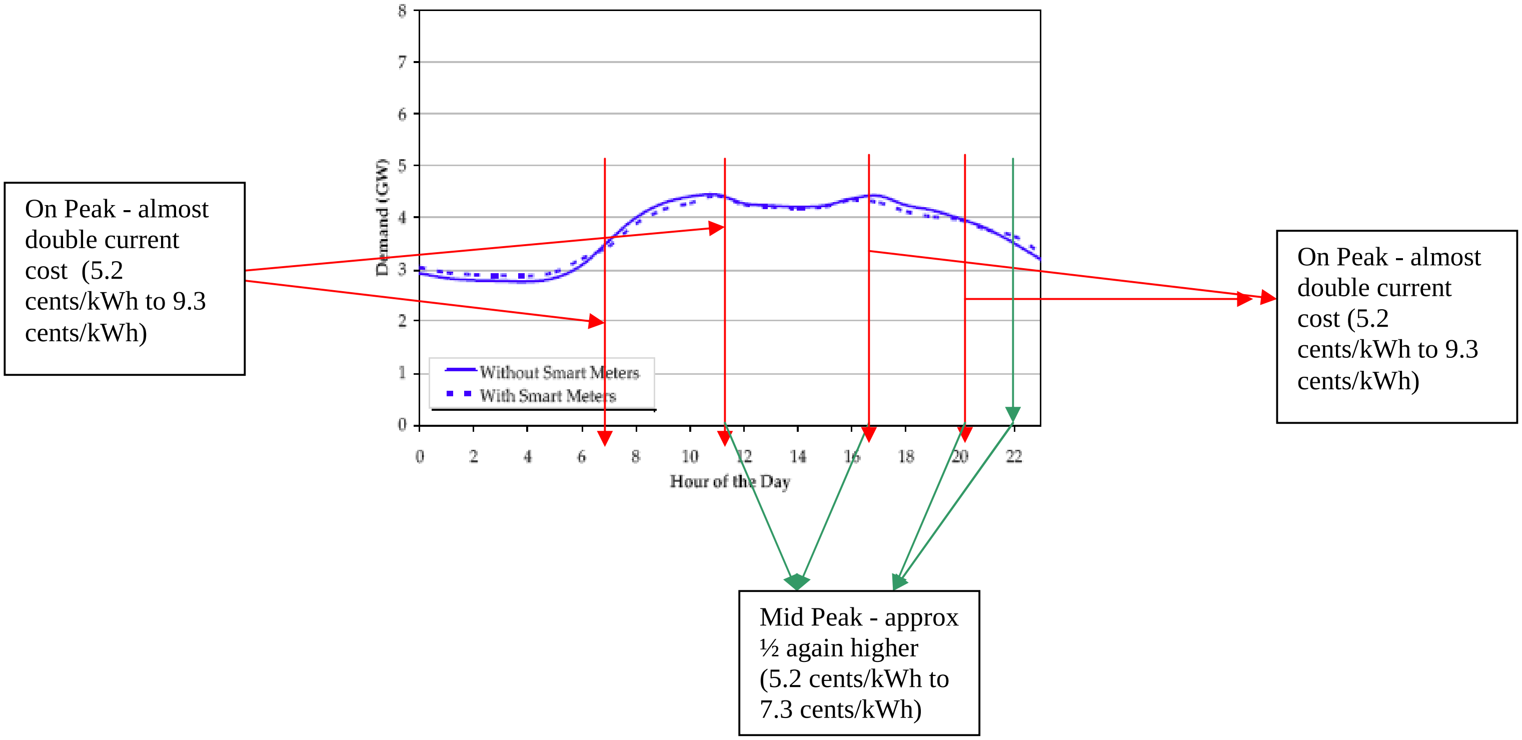
There are 3 time-of-use periods:

On-peak	**Mid-peak**	**Off-peak**
demand is highest	demand is moderate	demand is lowest
9.3 ¢ per kWh	7.3 ¢ per kWh	2.7 ¢ per kWh

* As of May, 2008
(from www.smartmersontario.ca, with updated pricing from the Ontario Energy Board website)

We have used the following charts, obtained from Exhibit EB-2007-0707 Exhibit D Tab 4 Schedule 1 Attachment 5 (Overview of the Portfolio Screening Model, prepared for the OPA, December, 2005, Navigant Consulting Ltd.). The lines have been added to demonstrate the impact of smart meter costs on small businesses during normal operating hours.

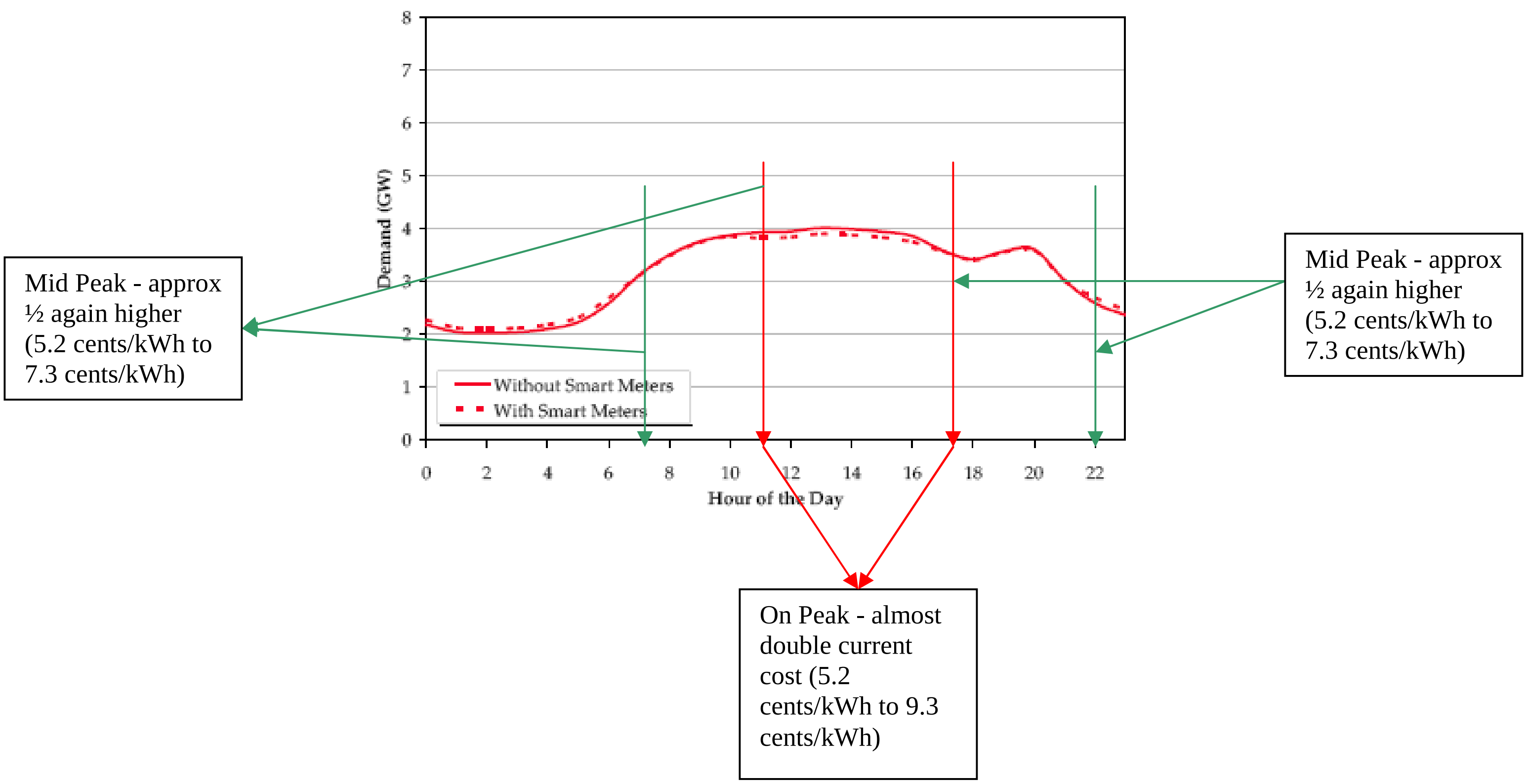
Figure 25: January Commercial Profile with and without Smart Meters and TOU Rates



Normal small business operating hours are totally within mid and on peak hours of the day. Electricity prices for these businesses will increase by 50%-100%.

(It is interesting to note that advice, such as doing laundry and dishwashing on off peak hours, is provided on the OEB website, but no advice to small businesses as to how to deal with TOU pricing.)

Figure 26 - July Commercial Profile with and without Smart Meters and TOU rates

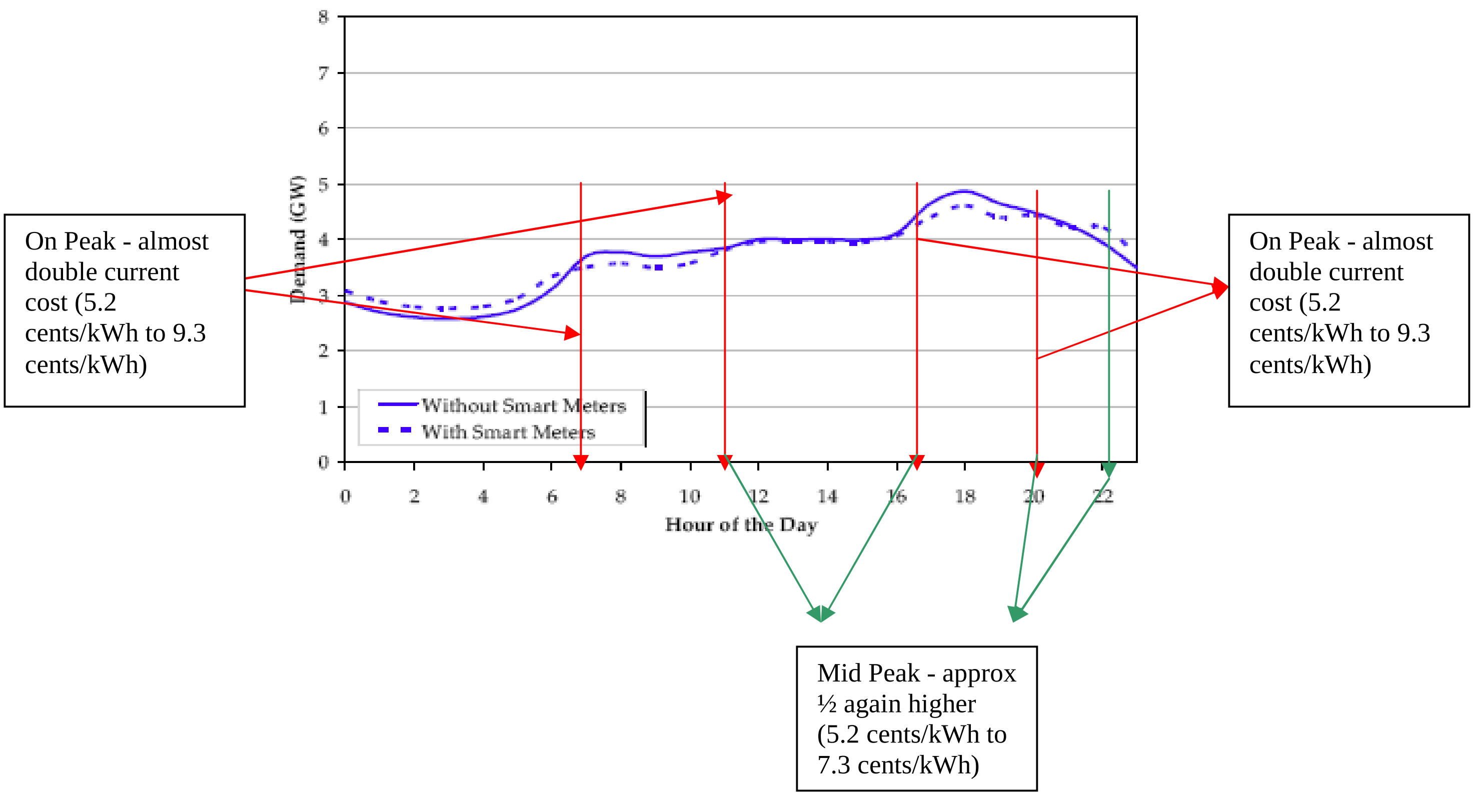


The cost impact on the commercial consumer is evident from these charts. The time of use metering system which will be implemented will cause marginal reduction in power consumption but at almost double the cost, as commercial/small business use is primarily during the highest pricing time.

The inability to load shift is evidenced by the information contained in the Navigant report, that, "Commercial customers report that peak usage is harder to curtail when critical business activity and electric use coincide with high price times. Also, businesses with high electricity intensity are less responsive than other customers. These findings seem to indicate that some businesses have less capacity to shift load simply due to the nature of their operations."
Likewise, the farming community, with little ability to load shift, will pay much higher costs. This will impact consumer goods, food, and all consumer spending.

Smart Meter Impact - Residential Use

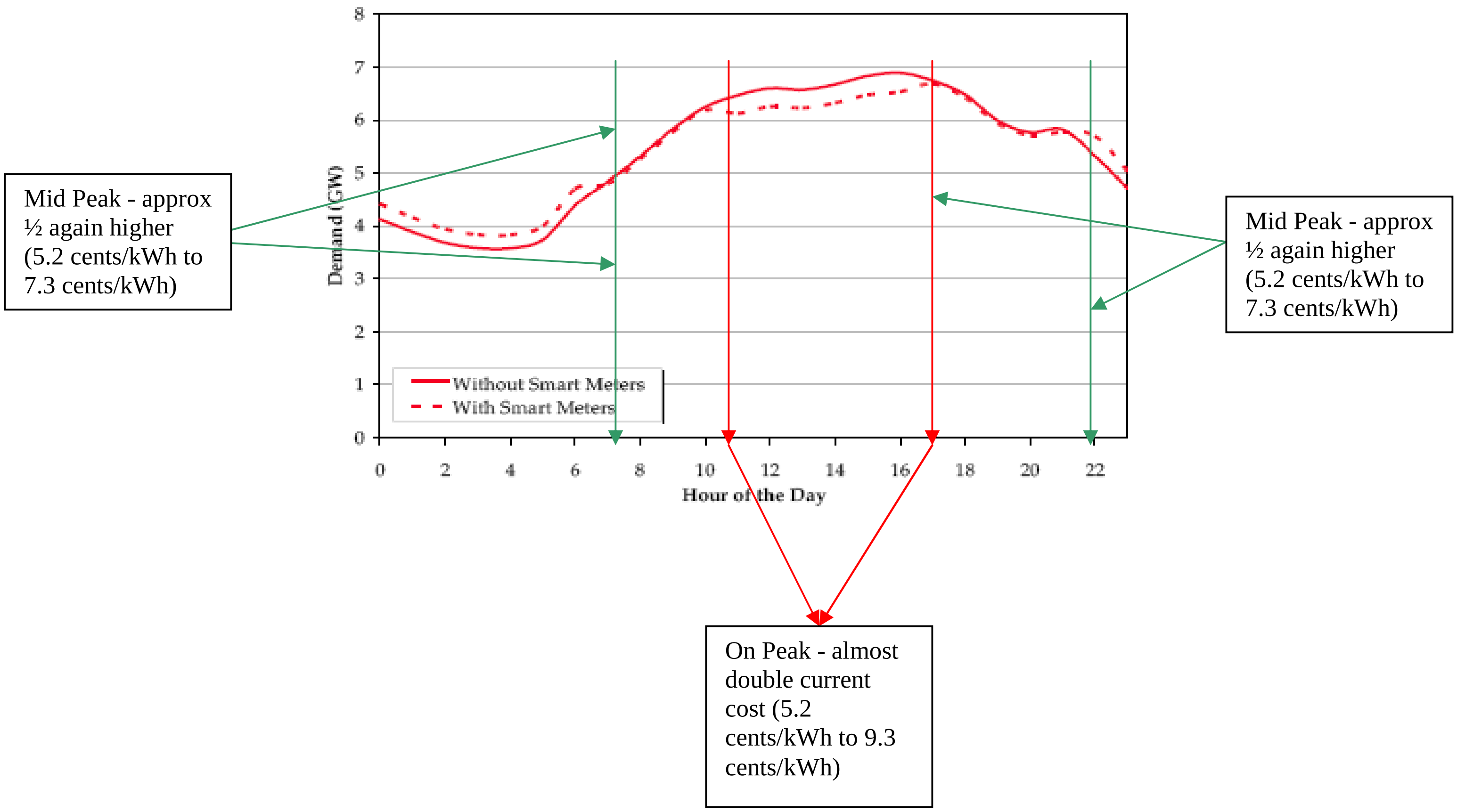
Figure 23: January Residential Profile with and without Smart Meters and TOU Rates



As this chart demonstrates, the highest TOU pricing coincides with increased demand in residential use due to normal activities during waking and pre-work/school preparation, etc. in the morning and arrival home, meal preparation, etc. during early evening hours. Much of this energy use cannot be shifted.

Although off peak use will be priced at ½ current rates (2.7 cents/kWh),

Figure 24: July Residential Profile with and without Smart Meters and TOU Rates



The following charts demonstrate some of the impact of higher electricity costs on daily use items. Note, that the price changes since these charts were prepared, representing higher mid and on peak costs, slightly lower off peak price.

Air Conditioning

		Today per kWh		TOU per kWh		
	Approx. Wattage	Tier 1 5.0¢	Tier 2 5.9¢	Off-peak 3.0¢	Mid-peak 7.0¢	On-peak 8.7¢
Air Conditioner (central) 2.5 TON	3,500	17.50¢	20.65¢	10.50¢	24.50¢	30.45¢
Air Conditioner (room) 9,000 BTU	1,050	5.25¢	6.20¢	3.15¢	7.35¢	9.14¢
Air Conditioner (room) 6,000 BTU	750	3.75¢	4.43¢	2.25¢	5.25¢	6.53¢
Fan (portable)	115	0.58¢	0.68¢	0.35¢	0.81¢	1.00¢
Ceiling Fan	60	0.30¢	0.35¢	0.18¢	0.42¢	0.52¢

*Maximum kWh - The costs listed are based on the maximum rating for the unit.

Clothes Dryers (and washers)

An average clothes dryer will consume up to 5 kilowatt-hours (kWh) for every hour of use,

	Approx. Wattage	Today per kWh		TOU per kWh		
		Tier 1 5.0¢	Tier 2 5.9¢	Off-peak 3.0¢	Mid-peak 7.0¢	On-peak 8.7¢
Clothes Dryer	5,000	25.00¢	29.50¢	15.00¢	35.00¢	43.50¢
** Clothes Washer	500	2.50¢	2.95¢	1.50¢	3.50¢	4.35¢

**Plus the cost of heating water

Electric Heating

	Approx. Wattage	Today per kWh		TOU per kWh		
		Tier 1 5.0¢	Tier 2 5.9¢	Off-peak 3.0¢	Mid-peak 7.0¢	On-peak 8.7¢
Baseboard - per 8 foot unit	2,000	10.00¢	11.80¢	6.00¢	14.00¢	17.40¢
Baseboard - per 4 foot unit	1,000	5.00¢	5.90¢	3.00¢	7.00¢	8.70¢

*Maximum kWh - the costs listed are based on the maximum rating for the unit

Electric Stoves

Since an electric stove is also a heavy electricity consumer, it makes sense to maximize every hour of use. For example, try to plan meals that allow more than one dish to be cooked in it. Or, consider using another option like a microwave or toaster oven, whenever you can.

	Approx. Wattage	Today per kWh		TOU per kWh		
		Tier 1 5.0¢	Tier 2 5.9¢	Off-peak 3.0¢	Mid-peak 7.0¢	On-peak 8.7¢
Electric Oven	5,000	25.00¢	29.50¢	15.00¢	35.00¢	43.50¢
Electric Stove - oven + 4 burners	12,500	62.50¢	73.75¢	37.50¢	87.50¢	108.75¢
Toaster Oven	1,250	6.25¢	7.38¢	3.75¢	8.75¢	10.88¢
Microwave Oven	1,000	5.00¢	5.90¢	3.00¢	7.00¢	8.70¢

Electric Water Heaters

The table below shows the costs to completely heat one 50 gallon tank of cold water.

	Approx. Wattage	Today per kWh		TOU per kWh		
		Tier 1 5.0¢	Tier 2 5.9¢	Off-peak 3.0¢	Mid-peak 7.0¢	On-peak 8.7¢
Water Heater - 50 Gallon tank Approx. 14kWh per full tank	3,800	70.00¢	82.60¢	42.00¢	98.00¢	121.80¢

*Maximum kWh - the costs listed are based on the maximum rating for the unit

(above charts from www.smartmetersontario.ca)

♦ The results of the OEB's Smart Meter Pilot Project in 2006-2007 revealed there was no applicable statistically significant load shifting from On-Peak periods as a result of the Time of Use (TOU) price structure alone. Minimal savings of an average of $1.44/month were identified as a result of load shifting. During the study participants achieved far greater savings of $2.73/month by simply reducing consumption of electricity.
These savings will likely not even offset the monthly smart meter fee.

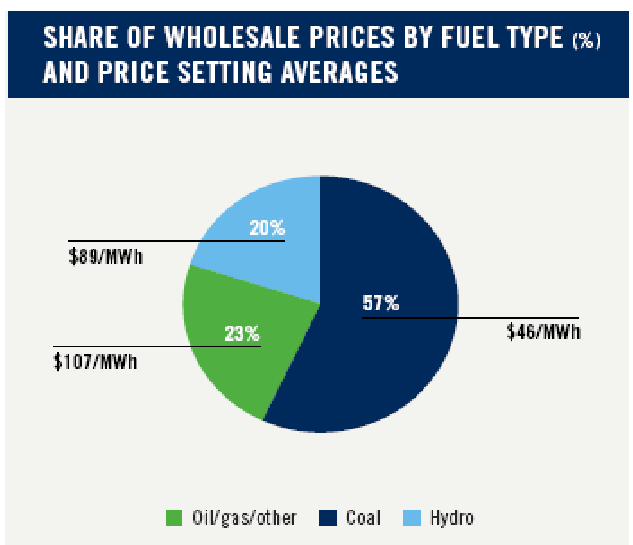
(For more analysis of this report, see letter from Tom Hughes to the OEB, attached as Appendix 2)

♦ The OPA suggests that prices for residential consumers will rise only 15%, and this can be offset by taking advantage of cost saving mechanisms. A review of this information leads to the conclusion that this is a highly unlikely scenario.

♦ In order for the "average" household to see a decrease in electricity costs, they will need to spend a considerable amount on new appliances and switch from electric to natural gas for water heating, cooking and clothes drying. While the hydro bill may be reduced, the gas bill will increase. It is unlikely that the outlay costs for these appliances and fuel switching will ever be recovered over the life of the appliances.

(ii) Impact of Natural gas-firedGeneration on Market Price

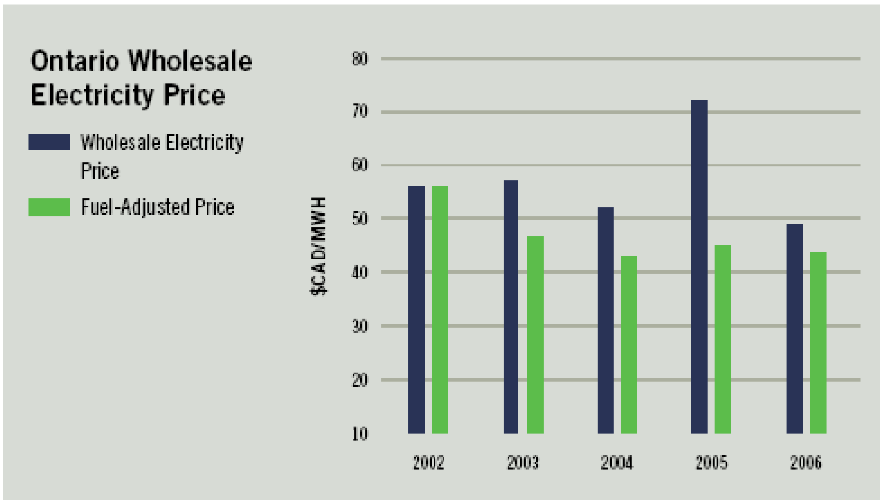
As depicted in the chart below, coal-fired generation currently sets market price approximately 55% of the time. Once coal-fired power is removed from service, natural gas is expected to set market price 85% of the time (Union Gas), at more than double the cost.



(IESO 2005 Annual Year in Review)

♦ The full impact of the coal replacement with natural gas-fired generation was captured in the CIBC World Markets Report of July, 2007, which estimates that this move would cause electricity prices to rise 60%-70%, or roughly 6.5% per year. ("Can Ontario Shutdown Coal and Keep the Lights On?", Benjamin Tal, CIBC World Markets Inc.)

♦ The following chart shows the impact of higher natural gas costs. Note 2005. "The substantial increase in the hourly prices in 2005 is attributed to the increase in the price of natural gas following hurricanes Katrina and Rita, with those prices being 40 per cent higher in 2005 than in 2004. ... This also illustrates how in a market model, changes in fuel prices such as natural gas, a major component of the cost to produce electricity, have an immediate and direct impact on the price of electricity." (IESO - 2007 Market Outlook)



♦"... electricity prices in Ontario dance very closely to the tune of natural gas. The surge in natural gas prices during Katrina led to a 40% increase in electricity prices in Ontario. On average, a one percentage point increase in natural gas prices leads to 0.5 percentage point increase in electricity prices in Ontario." (CIBC World Markets Inc., July 18, 2007)

♦ Navigant Consulting advises, "Higher than forecast natural gas prices have been a primary contributor to higher than forecast electricity prices in the spot market. Preliminary analyses show that for every 10% increase in natural gas prices, Ontario electricity spot market prices would increase by approximately 6%. It is notable that both the natural gas price and the electricity spot market price have each increased by 32% relative to forecast." (Monthly Variance Explanation April/05 – October/05)

♦ According to the Electricity Conservation & Supply Task Force, Final Report, "Coal-fired generation is today's lowest cost electricity-generation fuel and has set the market-clearing price 56% of the time in Ontario since market opening. If that segment of the market is removed, it is likely that the market-clearing price will be predominantly set by higher priced natural gas generation. This will have a significant effect on the price Ontarians pay for electricity."

♦ There are more than 50,000 businesses in Ontario, representing roughly 40% of load in the province. These companies pay the wholesale price through their LDC. (IESO 2005 Annual Year in Review)

♦ "Manufacturing is the single largest sector of the economy (17.5% of GDP) employing over 1,000,000 people directly in this province ... for every dollar invested in the manufacturing sector there is an additional $3.05 in economic activity." (Canadian Manufacturers and Exporters) Ontario generates half of Canadian factory output.

♦ “Today's increased globalization means that Ontario faces a more challenging and competitive environment than ever before. Ontario's future prosperity depends largely on its ability to continue to adapt, innovate and strengthen its competitive advantage. … Reliable electricity supply and price stability, which keep Ontario's economy competitive and benefit all consumers, are central to the government's plan.” (Ministry of Finance, “2006 Ontario Economic Outlook and Fiscal Review”)

♦ The OPA acknowledges that “An increase in electricity prices may have adverse macroeconomic effects on the provincial economy in terms of employment losses and may hinder the effectiveness of Ontario businesses that compete outside of the province.” (OPA – Sustainability Discussion Paper)

♦ In spite of the above information, the OPA has indicated that "macro-economic impacts of the Plan on the Ontario economy in terms of positive or negative impacts on jobs and investment" were not considered. (Response to AMPCO)

♦ According to the Finance Ministry “Ontario has the largest agriculture sector of any province, with sales of $8.2 billion in 2005. The government recognizes that Ontario farmers face challenges from a variety of external factors.” According to The Ontario Federation of Agriculture, “Without reasonably priced power the production and processing of food in Ontario would be uncompetitive and likely extinct. Agriculture is Ontario’s second largest industry. Reliable and reasonably priced power is essential to its sustainability.” (Stakeholder submission to the OPA)

♦ Effective April, 2009, the "MUSH" sector will start paying the hourly market price. The higher costs to educational, municipal and medical facilities will be passed to the taxpayer.

♦ The following excerpt from "Energy Efficiency Opportunities in Ontario Hospitals", February 2006, gives some insight into hospital energy costs and the impact of higher electricity rates:

"Ontario hospitals are the single largest provincial government expenditure... Due to the nature of their operations, hospitals have the highest energy intensity of all publicly funded facilities. ... A recent study of several large community hospitals identified that utility costs represent approximately 47.34% of their total plant operations and maintenance expenditures. ... Electricity costs typically represent about 50% of total utility cost for hospitals or about 23.7% of total plant operations and maintenance costs. Since deregulation *(2002)* of the electricity market in Ontario, hospital electrical prices have been protected under the province’s regulated rate protection plan. The MUSH sector will no longer be eligible under current legislation for price protection beginning in April 2008. There is the potential for dramatic price increases for hospital electrical costs at that time."

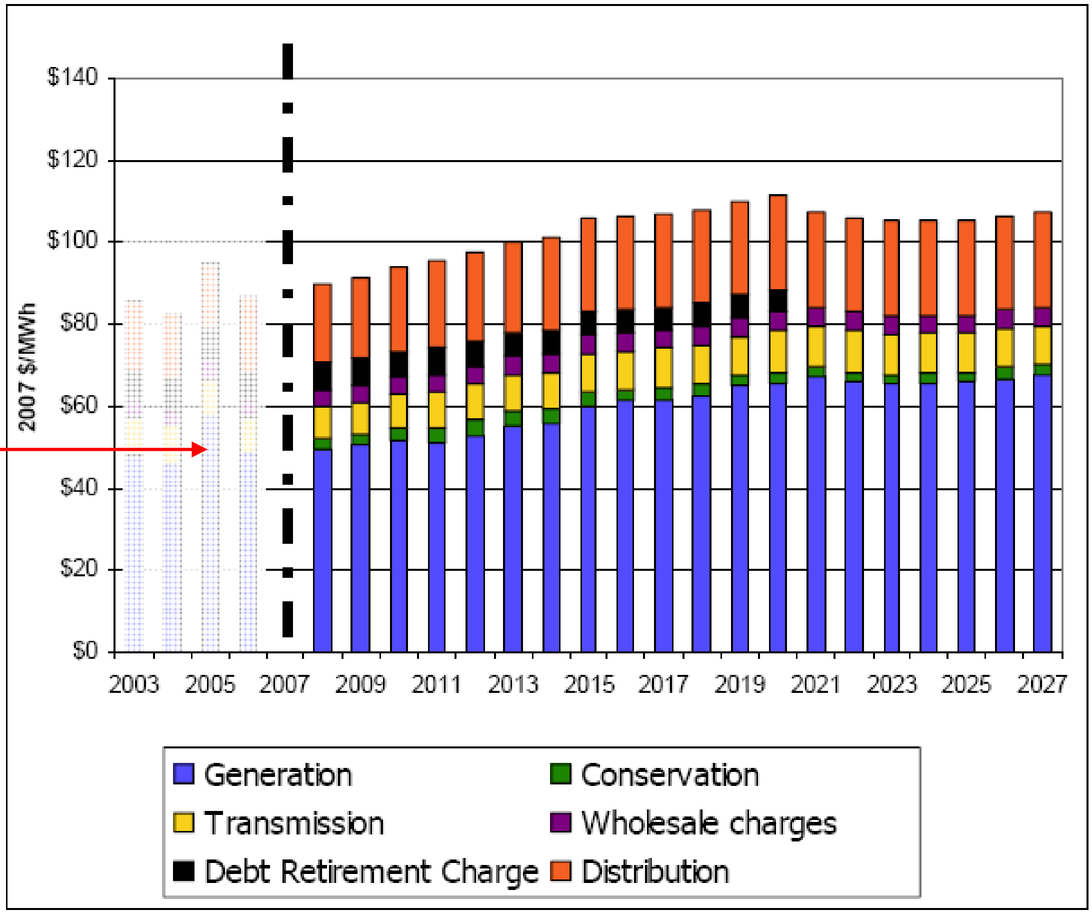
♦ Hospital operating costs are already increasing at a rate of 8% a year.

(iii) OPA Cost Assessment of the Plan

♦ The OPA has provided the following chart to demonstrate overall cost increases expected over the life of the Plan.

Figure 21: Current Estimate of Average Unit Cost (2007 $/MWh)

Note the higher costs for generation in 2005 - as noted above, this resulted from higher natural gas costs - OPA has not given sufficient consideration for the impacts of gas-fired generation going forward



Source: OPA

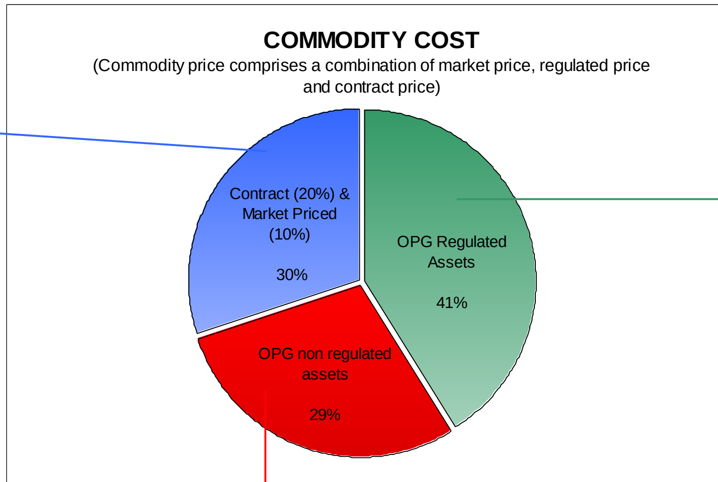
(EB-2007-0707 Exhibit I Tab 38 Schedule 67 Page 4 of 4 Filed: June 18, 2008)

With respect to the Commodity (Generation) Costs, note the following:

HOEP Market Pricing

OPG Lennox, Baseload Hydro > 1900 MWh; 15% of remaining unregulated Private generators - contract & market (NUGS, Bruce nuclear)

Imports



Baseload - consistent generation - Approx 67.5 TWh
Average Price $45/MWh

Nuclear - Darlington, Pickering (6600MW)
50 TWh +/- $49.50/MWh

Baseload Hydro
Niagara & St. Lawrence River plants - first 1900 MWh generated in any given hour
17.5 TWh +/- $33/MWh

Capped - 85% of following assets @ $47.00/MWh- Approximately 38TWh

Balance of OPG Hydro; 17 TWh+/-

Coal Stations ; 30 Twh +/-

Approximately 70% of electricity consumption is currently hedged
Monthly Global Adjustment and OPG Rebate to consumers

As resources included in the "green" area - ie OPG nuclear - and those in the "red" area - ie coal power - decrease, the "blue" area increases, thereby impacting the market price
This also impacts the amount of OPG rebate or global adjustment, transferring that money from consumers to private marketers

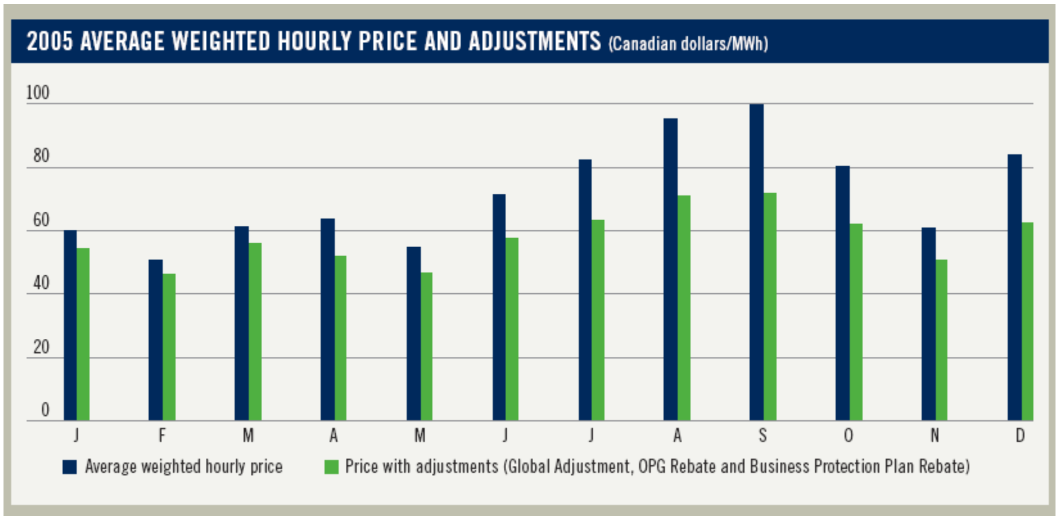
Impact of Potential Changes -

(i) As OPG assets are retired (coal plants - Pickering B) and are replaced by private generators (natural gas plants; Bruce Power), the market share portion rises - less resources subject to regulation
"OPG revenue cap on heritage assets stabilizes OPG revenues, stabilizes prices and mitigates market power." (AMPCO)
Higher prices - higher market power - greater volatility in pricing

(ii) As higher priced power is introduced into the system - i.e. wind and solar - nothing to offset or mitigate the costlier resources

(iii) Market price will be set primarily by natural gas (85% of the time, according to Union Gas). All generators in the queue receive market price, but significantly less resources impacted by capped rates. Therefore, the monies returned to consumers via OPG rebate or global adjustment - and revenue to OPG which offsets higher resources costs - will be swallowed up by private merchant generators.

The following chart shows the difference between average hourly price and the price with the rebate and/or adjustments.



IESO Market Year in Review - 2005

Table 13: Current Estimate of Average Unit Cost (2007 $/MWh)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Generation	48	46	58	48	-	50	51	51	51	53	55	56	60	62	62	63	65	66	67	66	65	66	66	67	68
Conservation	0	0	0	0	-	2	3	3	4	4	4	4	4	3	3	3	3	3	2	2	2	2	2	3	3
Transmission	9	9	9	9	-	8	8	8	9	9	9	9	9	9	10	10	10	10	10	10	10	10	10	9	9
Wholesale charges	4	4	5	4	-	4	4	4	4	4	4	4	4	4	4	4	4	5	5	4	4	4	4	4	4
DRC	7	7	7	7	-	7	7	6	6	6	6	6	6	6	6	6	5	5	0	0	0	0	0	0	0
Distribution	17	16	16	19	-	19	19	20	21	22	22	22	23	23	23	23	23	23	23	23	23	23	23	23	23

Source: OPA

(EB-2007-0707 Exhibit I Tab 38 Schedule 67 Page 4 of 4 Filed: June 18, 2008)

<u>Generation Costs</u>

♦ The chart shown on page 2 demonstrates the required new resources, representing a replacement of about 80% of existing supply. Power production will increase by 30%-150% according to supply source.

♦ The 2005 costs for generation demonstrates higher costs associated with natural gas-fired generation, a warmer summer, and lower hydroelectric production. Although natural gas will replace coal for intermediate and peaking power; will set market price the majority of the time; and will not generate rebates to the public to offset higher prices, the 2014 generation costs anticipated by the OPA - when coal-fired generation is removed from service - are lower than the 2005 generation costs.

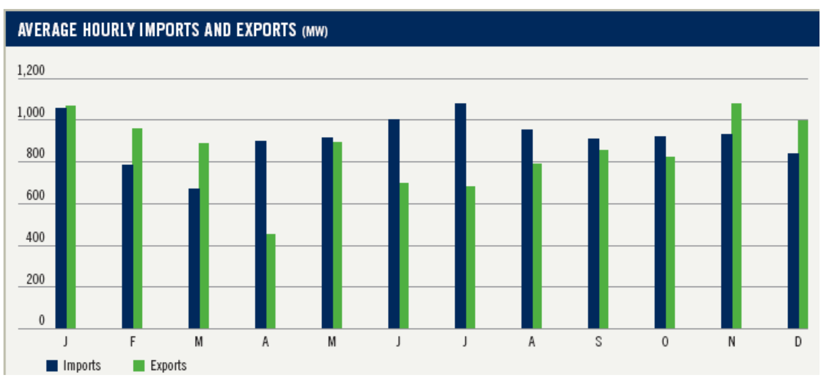
♦ The OPA advises that the generation costs for the 2008-2010 period are lower because "the price of gas at Henry Hub is forecast to drop from US$8.10/MMBtu in 2008 to US$6.83/MMBtu in 2010". (Response to AMPCO). However, natural gas prices are already significantly higher this year.

♦ The OPA has not done any modeling of the impacts of the costs associated with CO_2 emissions, stating that "GHG emissions decline significantly over the plan period (Exhibit G-3-1, 16 Figure 1). The cost impacts on Ontario electricity prices are expected to be small because the decline of GHG emissions is large." This is an inaccurate statement. GHG emissions from natural gas-fired generation will increase significantly.

♦ According to the above chart, the generation costs increase by 40% over the life of the plan. ($48/MWh in 2006 - $68/MWh in 2027). However, the OPA has merely factored the percentage of generation each resource will produce, and determined cost according to projected prices. (See Table 3.4 - Summary of Generation Assumptions, "Integrating the Elements" Discussion Paper) OPA has not factored in market influences, imports, etc.

♦ The OPA has used a cost assumption of $63.00/MWh for power from the refurbished Bruce A units. However, as pointed out by the Auditor General, this price will escalate annually based on increases in the Consumer Price Index (CPI) resulting in higher price by the time the refurbished units become operational. Also, the method and rate of CPI calculation "trades off lower prices in the earlier years for higher prices in later years". A significantly higher CPI rate was used in this deal as compared to any other.

♦ The following breakdown of commodity costs according to resource type demonstrates inconsistencies and cost variances from those used in the IPSP costs. Compare Table 5 below, with Table 3.2 extracted from the IPSP "Integrating the Elements Discussion Paper".



(IESO Market Year in Review - 2005)

Transmission Costs

The OPA has indicated that indirect costs associated with transmission, such as "overhead, escalation, contingency and interest during construction" were not included in the IPSP costs. (Response to AMPCO) Likewise, "The estimated $4 for transmission does not include the incremental OM&A costs." (OPA) Some of the transmission cost estimates "have an accuracy range of about +/- 30-50%".

Wholesale Charges

The above Table 13 indicates that the wholesale charges remain flat over the period of the IPSP. However, there are 6 categories included in this fee which represent the costs to operate the electricity system and market including OPA and IESO costs, congestion management charges, and ancillary services (which includes operating reserves, black start capability, reactive support and voltage control). With the radical changes taking place in Ontario's electricity system, these charges will have escalated, and are likely to continue to rise as more market and contract generators are added to the system. OPA expenses alone for planning purposes increased from $31 million in 2005 to $57.4 million in 2007.

Debt Retirement Charge

CAE Alliance has asked the Ministry of Energy for an assessment of amount owing. Although this has not been forthcoming, a Senior Policy Advisor advised us that "very little" had been paid toward the debt in spite of paying for a number of years now. As noted by the Canadian Manufacturers and Exporters in their Interrogatories, "The Ontario Electricity Finance Corporation's ("OEFC's") annual reports indicate that the DRC (Debt Retirement Charge) will end when the residual stranded debt is paid off, which the OEFC estimates will occur between 2012 and 2020. ..."

(iv) Costs not included in the IPSP

There are many costs that the OPA has not included in the Plan assessment. There are also indirect cost implications from choices made under the IPSP that impact the Ontario ratepayer and taxpayer. These direct and indirect costs will affect the Ontario economy as a result of the IPSP.

Some of these include:

- the economic cost of unused baseload generation is not attributed - ie in cases of surplus baseload generation when hydro facility - "spill" (bypass the turbine-generators)
- transmission costs to facilitate new natural gas-fired plants in SW Ontario - estimated by Hydro One to be $60 million (gas generators will contribute only $6 million)
- decommissioning costs for coal-fired units
- potential cost overruns on Bruce refurbishment (already over budget and behind schedule)
- "Black start power is an ancillary service offered by generators and procured by the IESO consistent with Chapter 7, section 9 of the market rules."(OPA) - It does not appear that the OPA therefore has considered this cost - which will likely be provided by natural gas resources - into the overall plan cost
- cost assessment for fuel switching does not include consumer cost for new appliances and cost for implementing natural gas in place of electricity
- many costs identified by the Auditor General regarding the Bruce units, which have not been factored in to overall future generation costs - The provisions and changes to Bruce contracts results "in ratepayers paying the financial equivalent of a price of $71.33/MWh for the additional energy from refurbishment
- increased turbine costs for wind generation; nuclear power components; transmission lines
- The impact on industrial and other natural gas users - which could result in closures and job losses - has not been fully explored, or assessed by the OPA.
- Natural gas for power generation is exempt from Ontario fuel taxes, impacting those others that compete for gas supplies. This impacts consumer prices and ultimately industrial presence in Ontario.
- Bonuses promised to gas-fired power producers from completion of facilities within designated time frames
- payments to generators of production incentives, sales tax abatements, favourable income tax treatment, direct subsidies for capital costs, direct capital incentives
- higher gst on higher electricity prices as included on energy bills
- There has been no cost assessment of the impacts of removing coal fired generation - which moderates provincial electricity costs - and subsequent replacement with much higher cost natural gas.

Summary

In reviewing the economic prudence and cost effectiveness of the IPSP as a whole, the CAE Alliance is asking the Board to consider the implications of high natural gas prices on market price; the impact of reduced OPG rebates/global adjustments; and the many costs not included in the OPA submission of information to the Board.

ISSUES

For the remainder of this submission to the Board, the CAE Alliance will refer to the Issues List, as determined by the Board. We will reference the Issues and Questions in order, and by number. However, we will not be addressing all of the issues, nor all of the questions pertaining to each issue.

Conservation

General

The OPA consistently notes that Conservation/Demand Management (CDM) is considered a "first resource" and is the first consideration for resource acquisition. "One-sixth of the projected budget - more than $10 billion - is to be spent on conservation alone." (OPA Quick Facts)

In order to adequately answer the questions posed in the Issues List, it is necessary to determine the degree of success reached to date. This process is obfuscated by reporting of inaccurate information and overstating the impact of CDM to this point in time. Consider:

♦ Ontario has had no prior methodology for tracking CDM. There is insufficient evidence of program success to determine with any degree of reliability what can be relied upon for planning purposes.

♦ This is evidenced by the OPA's response to AMPCO's interrogatory, "What has been the attainment to date, categorized by end-use technology, with respect to these goals, and what has been the contribution of each of the OPA's CDM programs to the totals attained?" The OPA has indicated that "The results of Conservation programs are currently being validated in accordance with the OPA's EM&V protocols and will be provided when they are available."

♦ Naturally occurring Conservation was included in meeting the 2007 target.

♦ The Conservation Officer's Annual Report 2007 notes that "The actual Ontario system peak in 2007 was 25,737 megawatts (24,820 megawatts weather-adjusted), on June 26, 2007. This peak is 1,268 megawatts lower than the highest peak demand in 2006 and represents a decrease of almost five percent."

The 2006 highest peak occurred August 1, 2006, at 27,005 MW, i.e. 1,268 MW higher than the 2007 peak. However, according to the IESO, the weather adjusted peak for August 1, 2006 is recorded at 22,890 MW demonstrating that in reality, the energy use at peak was **1,930 MW higher** in 2007 than 2006. (24,840 weather adjusted 2007 peak minus 22,890 weather adjusted 2006 peak) (IESO 18 Month Outlook, Sept. 10, 2007)

♦ The Conservation Officer's Annual Report 2007 indicates that "In 2006, the weather-adjusted per capita consumption had decreased by 2.5 percent. The results for the first six months of 2007 show that further progress has been made toward achieving the 10 percent target." This is not a verifiable claim. The IESO 18 Month Demand Forecast of Sept. 10, 2007, notes a 1.6 % decrease of demand in 2006, (not 2.5%), much of which resulted from erosion of industrial demand, not from "per capita" reductions in electricity use. Industrial electricity demand decreased by 11%.

♦ There is apparent confusion over what can reasonably be attributed to naturally occuring Conservation, and which program and/or agency delivered the demand reduction.

1. Does the IPSP 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?

♦ Regarding "fuel switching", if natural gas costs continue to rise, it is unlikely this will materialize. In fact, the opposite may occur and cause higher electricity use in place of gas. For example, when natural gas prices soared in 2001, many homeowners in BC switched to electric baseboard heaters rather than using their gas furnaces.

♦ If renewable electricity resources are expected to replace fossil fuel generation, it would be environmentally beneficial to switch from natural gas to electricity, which would have the opposite impact, i.e. raising power demand.

♦ The CAE Alliance believes that the OPA has not fulfilled the Ministerial directive mandate to "include load reduction from geothermal heating and cooling ... small scale customer-based electricity generation ...". Barriers to implementation include high fees for proponent applications and long wait times.

3. Is the mix of conservation types and program types included in the Plan to meet the 2010 and 2025 goals economically prudent and cost effective?

♦ As noted earlier, findings of The OEB Smart Price Pilot Final Report demonstrates that marginal benefits will result at great cost to consumers. See Appendix "A", an Analysis of this Report, conducted by Thomas Hughes Consulting (Corunna) Ltd., for the CAE Alliance.

♦ There are a number of programs, seemingly overlapping targets and agencies delivering programs, which makes it difficult to determine a cost/MWh of some of the CDM initiatives.

♦ Some of the programs cannot be deemed cost effective. For example, the Peaksaver program designed to reduce air conditioning demand during summer days is expected to be activated 10 times this summer, for a savings of up to 45MW each time it is activated. More than 90,000 homes and businesses have signed up so far, with each having received $25.00 to have the device installed. (OPA website) This would mean that $2,250,000.00 has been paid to reduce demand by **up to** 45 MW on 10 occasions through the summer, this latest being for a 4 hour period!

♦ The Directive calls on the OPA to use "innovative strategies" to fulfill CDM requirements. The OPA's ideas are vague and the relevant cost assessments are equally so. "Given the difficulty and inherent uncertainty in forecasting such things as the future capital costs of technology and the future impact of social marketing on behaviour, ... the importance of cost-effectiveness tests in evaluating these innovative strategies is somewhat diminished and an increased reliance on judgment is required." (Response to Board)

♦ We believe that there are serious omissions in the OPA’s cost benefit analysis of this program, which if corrected would indicate that there is little if any benefit to be gained.

▪ While the Conservation Bureau gives the budget for the CDM program to be $10.2 billion less than half of this amount is used in the cost-benefit analysis.

▪ Table B14 –CDM Costs and Benefits, in the revised CDM section of the IPSP issued in December 2006, gives the avoided costs as $11.5 billion and the Resource cost as only $4.5 billion, not $10.2 billion, for “net benefits of roughly $7 billion plus or minus $2 billion given our assessment of the uncertainty in both the costs and the benefit estimates.”

▪ Tables B12 and B13 CDM Costs 2008-2025, show the total Delivery Costs, which when added up, to be approx $4.6 billion and the Societal Cost to be approx $5.7 billion for a total of $10.3 billion.

▪ It is very clear that the Societal Costs have been totally ignored in the analysis giving the general public a very distorted view on the (lack of) benefits. This is confirmed by at least three statements in the IPSP relating to the smart meter program.

IPSP CDM –Revised

P86. "Since the government has already decided on this program, there are no new costs"

P91. "In Demand Management, the small customer (TOU) component has not been allowed any costs as the primary cost, improved metering, has already been committed. This, in part, explains Demand Management's high benefit"

P92 (Summary of findings) "Demand management appears to have the highest benefit relative to the costs involved. However a large part of those costs, the cost of smart metering, have not been included as they have already been either spent or are committed to be spent.

▪ This whole approach is totally flawed and needs to be corrected. It is just the same as saying the Nuclear Refurbishment program will cost nothing since it has already been committed!

▪ Adding the approx $6 billion Societal Cost into the equation would result in benefits of perhaps $1 billion to a loss of $4 billion.

▪ In preparing the Cost-Benefit analysis the OPA has gone against the procedure of one of the references frequently used in the IPSP i.e. the California Standards Practice Manual.

See quotes below.

"Total Resource Cost Test [1] Definition

The Total Resource Cost Test measures the net costs of a demand-side management program as a resource option based on the total costs of the program, <u>including both the participants' and the utility's costs</u> ...

... <u>The costs in this test are the program costs paid by both the utility and the participants</u> plus the increase in supply costs for the periods in which load is increased. Thus all equipment costs, installation, operation and maintenance, cost of removal (less salvage value), and administration <u>costs, no matter who pays for them, are included in this test.</u> Any tax credits are considered a reduction to costs in this test. For fuel substitution programs, the costs also include the increase in supply costs for the utility providing the fuel that is chosen as a result of the program…….

1 This test was previously called the All Ratepayers Test"

As ratepayers we need to understand the true costs of the government's energy plan. We urge the Board to make this happen. In particular, it would appear that the IPSP is trying to deliberately cover up the true cost of the smart meter program. Considering the huge cost of this program there need to be a lot more scrutinizing of the economics to find more cost effective ways to achieve results

Renewable Supply

6. Does the IPSP 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?

♦ Although the OPA indicates that the most promising new hydroelectric and wind resources are located in Northern Ontario, the 4 different case scenarios provided for contingency options includes a scenario where there is "no northern development".

The variability of wind generation was to be mitigated by varying the location of wind farms throughout the province. The decision to not develop the northern potential will impact this factor.

If the northern hydro potential is not realized, there will be less intermediate resources to displace coal.

♦ The proposed IPSP does not provide sufficient planning for either installed capacity of new renewable resources, or the projected energy production from these resources. Equally important, the IPSP fails to consider the required generating characteristics required at each planning stage to ensure sufficient peak, intermediate and base load generation.

♦ The IPSP identifies renewable resources which could be added to the supply mix later in the next decade, but has not established a plan for procuring these resources. Those most promising are located in northern Ontario and therefore require considerable cost and difficulty to implement.

♦ The IPSP delivered to the OEB is not consistent with the preliminary information contained in the Discussion Papers and the Preliminary Plan delivered earlier this year. It is therefore difficult to compare the information in terms of expected TWhs of production with the planned resources.

♦ Approximately 8,250 MW of installed renewables, primarily hydroelectric (7,850 MW), produces 34-37 TWh of power (36 TWh in 2005 – OPA Dec. 2005). A total of 49 TWh of power production from renewables is expected by 2015, an increase of 12-15 TWh.

3,300 MW of additional renewable resources is expected by 2015 - 2,000 MW from wind generation; 900 MW from new hydroelectric. The OPA anticipates 3.5 TWh of production from new hydro resources, leaving new wind power to produce the bulk of the remaining 9-11 TWh. Considering that wind resources have a 17%-20% capacity factor (IESO indicates 10%) it is impossible to expect this amount of production from wind generation. (See Table 1.1 - Preliminary Plan - Energy Production TWh)

♦ Likewise, by 2020, an additional 910 MW of installed wind capacity; 390 MW of hydroelectric and 200 MW biomass is expected to produce a further 11 TWh of production.

♦ There are significant uncertainties regarding the installation of these resources, particularly transmission requirements and environmental assessments.

♦ Consideration has not been given to the concern that water levels are decreasing, with the potential to affect hydroelectric production. The drought like conditions of 2005 impacted power production from these facilities (IESO). Hydro production was down in the first quarter of this year (2007) due to below normal water levels. (OPG)

▪ The IESO has advised that coal replacement resources should closely resemble the withdrawn resources, i.e. in load following, load balancing, and quick dispatch abilities. The addition of intermittent resources, i.e. wind, increases the need for resources with these generating characteristics. The IPSP does not sufficiently address these concerns, other than to suggest plugging in natural gas generating facilities when any deficiency occurs, again, the "finger in the dyke".

7. Is the mix of renewable resources included in the Plan to meet the 2010 and 2025 targets economically prudent and cost effective?

♦ There is such a difference between minimum and maximum all-inclusive unit energy costs for hydroelectric, (Table 8 - Revised Table 17) $2.73 to $9.22 that it is difficult to assess whether these proposed facilities meet the criteria of this question.

♦ The OPA has procured high priced solar resources but has not fully developed the potential for biofuels such as biogas digesters or wood waste and agricultural bi-products for power generation or landfill incineration. The project fees and road blocks for the application process are impacting the uptake of these smaller generators. Maximizing this type of generation has the added benefits of reducing greenhouse gas emissions and augmenting the agricultural and forestry sectors that are both struggling.

Nuclear for Base-load

10. Does the IPSP plan for nuclear capacity to meet base-load requirements and limit the installed in-service capacity of nuclear power over the life of the Plan to 14,000 MW?

11. What is the base-load requirement after the contribution of existing and committed projects and planned conservation and renewable supply?

12. Is the IPSP's plan to use nuclear power to meet the remaining base-load requirements economically prudent and cost effective?

The CAE Alliance has concerns regarding power production that is required from nuclear units, whether there will be availability of new or refurbished units to produce the needed TWhs.

We are also concerned that the capacity factor for nuclear plants is overstated which will result in higher use of natural gas-fired generation, and use of gas-fired power for baseload.

The proposed IPSP states that, "after the contributions from existing and committed supply, planned Conservation and renewable resources are taken into account, there remains a base load requirement of 85 TWh. That base load requirement may be met by one of two candidates: nuclear power and combined cycle gas turbine generation ("CCGT")". (EB-2007-0707 Exhibit B, Schedule 1)
The OPA has determined that nuclear units are best suited to supply this base load requirement, although more power will be expected from less resources.

♦ Table 1.1 of the OPA Preliminary Plan demonstrates that in 2010, 91 TWh, and in 2015, 88 TWh will be required from nuclear facilities.

♦ In 2005 11,414 MW of installed nuclear capacity produced 79 TWh of power. During the years 2011-2018, the OPA anticipates 85-88 TWh, an additional 6-9 TWh, from 1,000 less MW of installed nuclear capacity, primarily from units that are reaching end of life.

♦ Existing nuclear units will reach end of life between 2013 and 2022. “Availability is lowest between 2016 and 2020 when a number of units are simultaneously on refurbishment outages.” … For purposes of overall adequacy, it will be especially critical to manage and maximize nuclear availability during this period.” (OPA Discussion Paper - Integration)

♦ Plans to provide the necessary refurbishment of units, and the installation of new nuclear facilities may be impacted by labour and material shortages. According to the OPA, “…the availability of skilled labour, long lead time for equipment and critical material resources can adversely impact scheduled completion dates and cost. … many nuclear units throughout the world also due for refurbishments, coordination will also be vital for Ontario companies to secure their place in line for materials and specialized companies …”

♦ "The OPA does not intend to procure any nuclear supply by the end of 2010." (EB-2007-0707 Exhibit B, Schedule 1) The timing for both new build and refurbishment of nuclear units is such that delays in planning at this stage could imperil the supply of necessary base load power.

♦ There are recently announced delays in decisions regarding progress of new nuclear procurement in terms of technology, as well as delays in determining whether Pickering B will undergo refurbishment. These delays will result in an increase in natural gas use for electricity, which will impact both reliability and affordability of power.

♦ The proposed IPSP indicates that "If OPG decides not to refurbish Pickering B, then the Plan assumes that the associated capacity of 2,064 MW will be replaced at a later time by new nuclear resources." However, Table 4, below, demonstrates that 1,074 MW of replacement power will be provided by natural gas facilities. This clearly violates the Ministerial Directive regarding the use of natural gas fired generation for base load requirements. (see next section of this document.)

Natural Gas Use

15. Does the IPSP 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?

16. Has the OPA, in developing the IPSP, identified opportunities to use natural gas in high efficiency and high value applications in electricity generation?

17. How can gas be used for peaking, high value and high efficiency purposes?

♦ The OPA has interpreted the Ministerial Directive to encompass almost any conceivable scenario under the umbrella of "high efficiency and high value use". The OPA interprets "high efficiency" in terms of economic consideration, but as only as a comparison between CCGT, SCGT and CHP. In consideration of natural gas use in general, power generation production in SCGT and CCGT utilizes gas at about 40%-50% efficiency. That would certainly not be considered a high efficiency or high value use when compared to home heating or industrial sources that use natural gas at a 95% efficiency.

♦ The Ministerial Directive to the OPA must be defined within the context of the Supply Mix Advice and Recommendations upon which the Directive was based.

♦ "Natural gas in the IPSP is being planned in accordance with the 'smart gas strategy' recommended in the supply mix advice, which places priority on maintaining the ability to use natural gas capacity at peak times and pursuing applications that allow high efficiency and high value use of the fuel." The context of the "Smart Gas Strategy" was the numerous references throughout the Supply Mix Advice and Recommendations to the risks associated with cost and supply of natural gas for power generation.

The OPA notes that "The price of natural gas over the IPSP planning period is a source of uncertainty that could affect how the smart gas strategy is implemented." and "Future gas prices, in part, support a strategy that favours high efficiency and high-value applications for gas-fired power."

"The intent is not to use gas for baseload generation but the smart gas strategy does contemplate its use as a high efficiency resource (such as with cogeneration or fuel cells), or its use for targeted purposes (such as with peaking units to relieve transmission constraints)." (OPA Supply Mix Discussion Paper)

"Under a smart gas strategy, gas-fired generation is used primarily in peaking applications and for local reliability." (OPA - IPSP Scope and Overview)

♦ The OPA has discussed the use of natural gas resources for inclusion in the Plan within the context of "feasibility, reliability, cost, flexibility, environmental performance and societal acceptance. (EB 2007-0707- Exhibit D, Tab 8, Schedule 1, pages 26-27)

♦ In order to address the Issues above (15, 16, 17), it will be necessary to discuss the use of natural gas from this combined context. We have addressed natural gas use already in part at Pages 4-5 (over reliance on natural gas) and at pages 16-17 (impact of natural gas generation on market price) as well as load following concerns discussed on pages 7-8.

♦ A fuller answer in the context of costs will be discussed at Issue 19, below; at coal-fired replacement, Issue 23; as well as the environmental assessment considerations at Issue 31 and 32.

♦ The government has imposed regulations necessitating the cessation of coal use beyond 2014. It is this initiative this is driving the significant implementation of natural gas-fired generation in Ontario. The need to balance the individual requirements of the Directive, while maintaining system reliability, has been marginalized in order to fulfill the coal closure requirement. The CAE Alliance maintains that this imperils system reliability and electricity affordability. Natural gas use is not a reasonable alternative to coal-fired generation at this time. Replacing coal-fired generation with natural gas-fired generation will have marginal, if any, environmental benefit, but at great cost to the Ontario economy.

♦ This is evidenced by the OPA's decision to utilize natural gas-fired generation in lieu of transmission installation. "...the construction of new transmission lines generally engender more community opposition and pose more significant regulatory challenges than siting new gas plants. As noted, this feasibility challenge was a consideration in the evaluation process particularly given that the reliability needs in some of the local areas are pressing." (Response to PWU)

♦ This "pressing " need to install gas-fired generation in order to remove coal-fired power was evident when the CAE Alliance questioned the OPA in respect of a natural gas facility proposed for the SW GTA. We were advised that "the government" is deciding what procurement process would be used, and that "all parties" are cognizant of the need for generation to be implemented in 2013.

♦ "The definition of 'peak' as used in the IPSP is based on an economic analysis ... it is established that simple cycle gas turbine ("SCGT") generating plants are more economic to install and operate than combined cycle gas turbine ("CCGT") generating plants if they are required to operate for 14 percent of the time or less in a year. Since SCGT plants have specifically been designed to operate as peaking resources, this economic analysis effectively establishes the definition of peak hours. In the IPSP, SCGT facilities are planned to meet peaking requirements." (OPA response to Board)
The OPA has indicated that simple cycle units gas-fired generators would operate to "mitigate impacts of wind variability on power quality and voltage performance." This would occur on a daily basis and would require simple cycle facilities to be on stand by mode to load balance. This would appear to contradict the above stated parameters for peak hour generation.
Daily load requirements, not theoretical models, will determine which resources will generate power for the grid, and when they will be required.

♦ We understand that there were more opportunities for CHP - the highest value/highest efficiency use of natural gas for power generation. However, project fees and process hurdles hindered the uptake.

18. How can gas-fired generation contribute to meeting transmission capacity constraints?

The Plan includes significant gas-fired generation in order to replace coal-fired generation. The OPA proposes implementing natural gas in place of transmission installation in certain areas. However, this may not be feasible in some areas due to transmission contraints. "The referenced gas generation projects (Northern York Region, Kitchener- Waterloo-Cambridge-Guelph and Southwest GTA Regions) are expected to be connected to the high voltage transmission system. At this time, the OPA has not specifically examined whether there are any distribution constraints in these regions which might affect the feasibility of the new gas plants." (Response to Electricity Distributors Association)

19. Is the IPSP's plan for additional gas resources for peaking, high value and high efficiency purposes and for contributing to transmission capacity constraints economically prudent and cost effective?

The use of natural gas for power generation in Ontario is neither economically prudent nor cost effective. The impact of natural gas use on market setting price was described in the earlier part of this document (pages 16-18). Other cost impacts are detailed below.

♦ "The affordability of electricity is a component of sustainability … supply projects will be selected based on their cost-effectiveness." (OPA) Natural gas fired generation is both costly and uncertain in terms of cost forecast. Fuel costs are variable and dependent on various factors. Other generating resources can be reasonably estimated. Not so with natural gas. Because fuel costs represent such a high percentage of operating costs, there is greater impact to price/MWh of power generation from natural gas than any other generating resource.

♦ The following chart shows that natural gas-fired generation is the most costly, with the exception of solar power. (The median range is shown here - gas generation costs are more expensive in the upper and lower scenarios as well).

Table 5: Commodity Costs ($/MWh) – Median Scenario

	2010	2015	2020	2025
Non-Prescribed Hydro	37	43	43	38
Non-Prescribed Coal	37	43		
Prescribed Hydro	38	38	38	38
Beck Tunnel	69	69	69	69
Prescribed Nuclear	52	52	52	52
Refurbished Prescribed Nuclear	74	74	74	74
Bruce A	74	74	74	74
NUGS	98	112	103	72
Renewed NUGs	137	127	116	109
CES Contracts	177	142	128	145
RES Contracts	81	74	68	63
New Nuclear	86	86	86	86
New Renewables	85	85	85	85
New Gas	200	152	126	151
Standard Offer	105	97	90	84
Standard Offer Solar	404	366	331	300
Uncontracted Supply	37	43	43	38
Imports	37	49	47	49

Source: OPA

(EB-2007-0707 - Exhibit 1, Tab 32 - Schedule 24)

♦ Coal closure and subsequent replacement with natural gas fired generation will cause electricity prices to rise to 60%-70% higher than they are now, or roughly 6.5% per year. This is "based on our assumption that natural gas prices will reach $12-$14/mmBtu by 2015." ("Can Ontario Shutdown Coal and Keep the Lights On?", Benjamin Tal, CIBC World Markets Inc., July 18,2007)
That was almost a year ago. In mid May 2008, natural gas futures for June delivery set a record of $11.675 per 1,000 cubic feet (closed lower at $11.30) on the Nymex market.

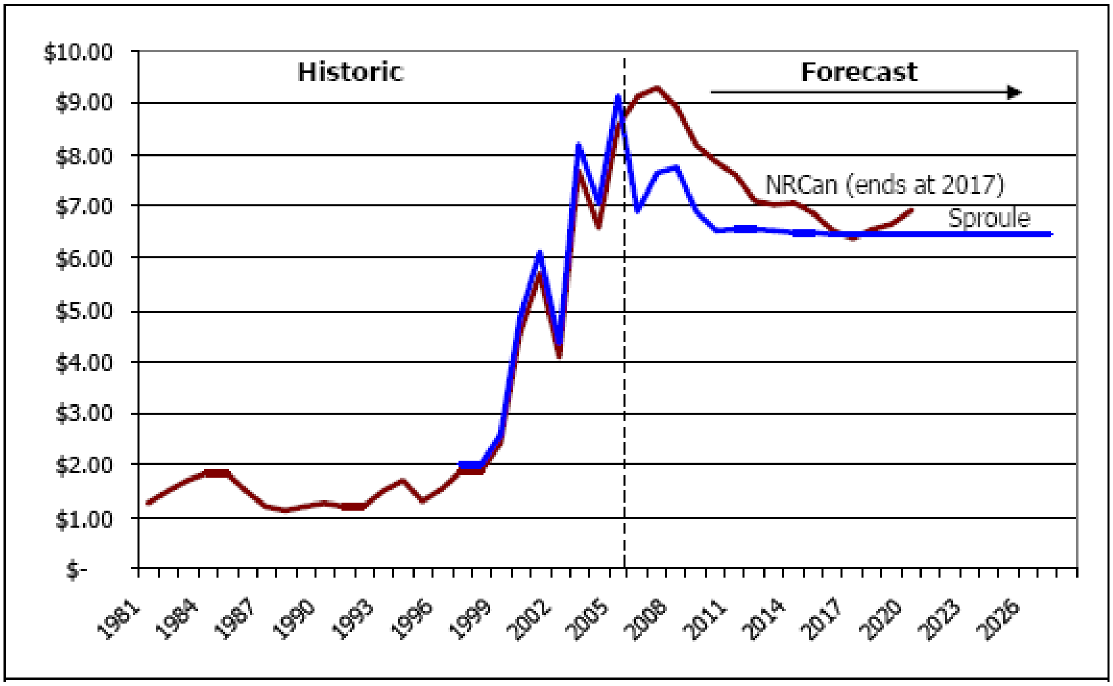
♦ Fuel costs represent over 50% of the levelised cost of electricity, and 90% of the operating costs for natural gas-fired power generation.

♦ The levelized cost of all technologies using natural gas as fuel is predominantly the fuel cost, and thus is highly sensitive to the price of natural gas. (CERI)

♦ Natural gas prices as of June 6, 2008 were $12.70/mmBtu.

♦ The OPA used the gas price forecast by Sproule Associates Limited to assess the viability of using natural gas-fired for power generation, as shown below.

Figure 4.11 – Forecast of Natural Gas Prices



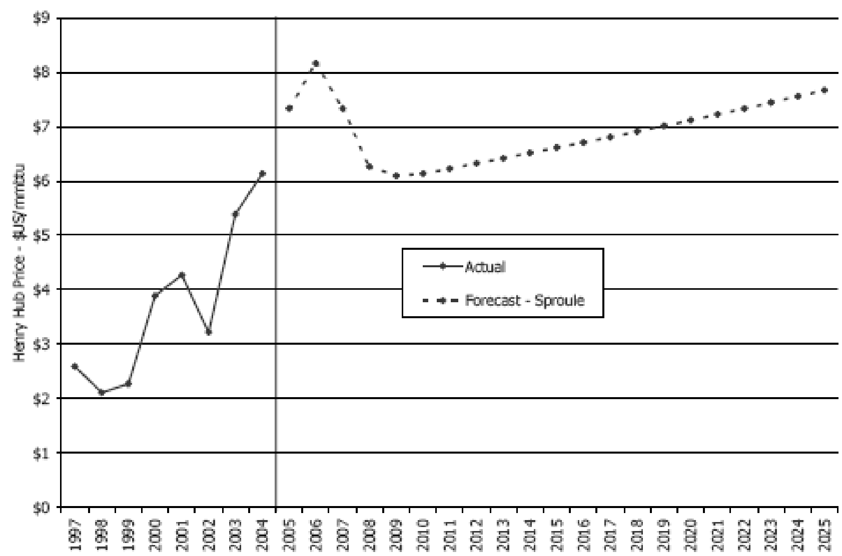
Notes:
1. The Sproule forecast was obtained from Sproule Associates Limited's website, dated September 30, 2006 http://www.sproule.com/prices/defaultprices.htm.
2. The NRCan forecast was obtained from Canada's Energy Outlook: The Reference Case 2006 http://www.nrcan.gc.ca/inter/publications/peo_e.html.

OPA Supply Resources Discussion Paper

Note, that the NRCan assessment shows a projected rise in natural gas costs at 2015.

The following chart is also a forecast produced by Sproule and used by CERI in their consultants' report to the OPA. The comparison demonstrates the statement that "There are considerable differences among published forecasts of natural gas prices, production, consumption, and imports. The differences highlight the uncertainty of future market trends."

Figure 9.4
Natural Gas Price Forecast from Sproule
Nominal USD/mmbtu



CERI - Canadian Energy Research Institute Electricity Generation Technologies: Performance and Cost Characteristics Prepared for the Ontario Power Authority, August, 2005)

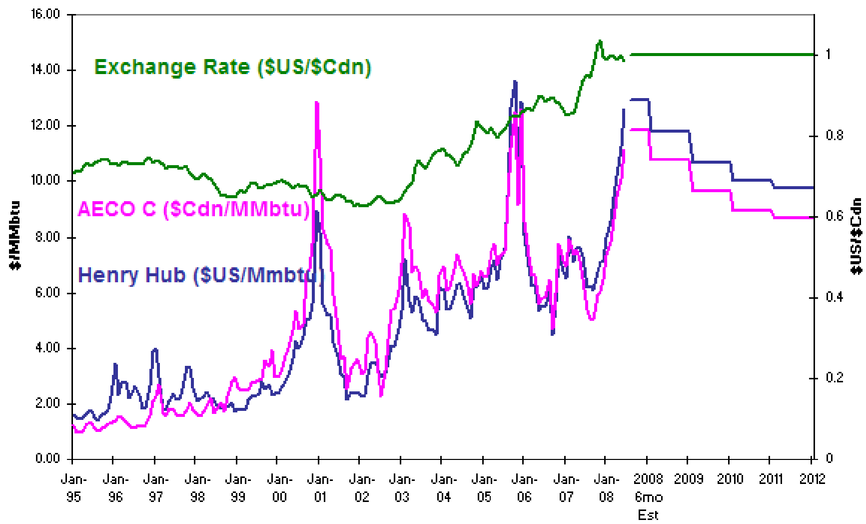
The following chart shows another forecast annual fuel price of natural gas at the Dawn Hub, this one predicting that natural gas costs will continue to rise. (EB-2007-0707- Exhibit 1, Tab 32, Schedule 36)

Table 1: Fuel Prices at the Dawn Hub

Year	Fuel Price ($/GJ)
2013	9.67
2014	9.81
2015	9.96
2016	10.10
2017	10.25
2018	10.45
2019	10.65
2020	10.86
2021	11.08
2022	11.29
2023	11.52
2024	11.74
2025	11.97
2026	12.21
2027 - 2033	12.45

Source: OPA

Natural Gas Prices - History and Forecast



This latest Sproule forecast demonstrates higher natural costs that the information OPA is currently relying on.

♦ The government cost benefit analysis prepared to in order to justify the coal closure, was based on costs much lower than current costs, as noted below.

Table 1. Levelised Cost of Electricity, $/MW (Derived from Data in the DSS report)

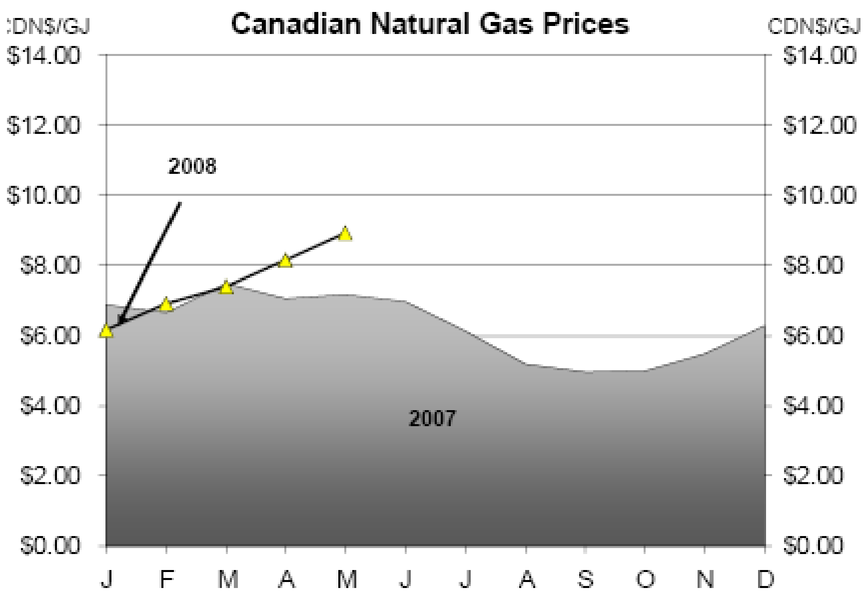
Coal as is	Coal with Stringent Controls	Coal Replaced With Gas @ 5.48USD @ 6.25CAD	Coal Replaced With Gas @ 7.00USD @ 7.98CAD	Coal Replaced With Gas @ 8.00USD @ 9.12CAD
$37	$51	$78	$93	$102

Using the mid point price for this year of say $7.00 US, the levelised cost of electricity from gas-fired generation would be $93 CAD/MW, 2.5 times that of the existing coal-fired generation or 1.8 times that of coal after installing stringent controls. Using a price of gas, $8.00 US, the price from gas-fired generation becomes 2.8 times that of existing coal generation and 2.0 times that of coal after installing stringent controls.

In that analysis greenhouse gas costs comprised 94% of the total estimated environmental damages with respect to coal fired generation. Even with this significant allocation of environmental costs, coal fired generation was a better choice than utilizing natural gas. This government report also noted that "Ideally, the GHG emissions being assessed should be based on a life-cycle perspective ... GHGs are associated with the production of natural gas (e.g. leakage during recovery and transport, burning of impurities) and the impact of these emissions is not captured in the damage estimates in this report." (Cost Benefit Analysis: Replacing Ontario's Coal-Fired Electricity Generation prepared for the Ontario Ministry of Energy, April 2005)

♦ Natural gas fuel costs are more than double now what they were in 2003 when the Liberal government determined to close coal fired power plants. Using OPG figures, it will now cost $85 million **more** to generate a terawatt hour of power using gas-fired generation than it did then.

Figure 1



Source: GLJ Energy Publications **Note:** Canadian price is the Alberta price at the AECO hub.

Price comparison - showing increase in 2008 over 2007 prices

Canadian Natural Gas Monthly Market Update, May, 2008 Natural Resources Canada

Natural Gas Market Fundamental	Percentage Change	
	Year-to-Year	Month-to-Month
Prices	25%	10%
Heating Degree Days	8%	-13%
Production	-3%	4%
Sales	8%	-4%
Exports	13%	4%
Imports	54%	15%
Storage	-35%	18%
Drilling	20%	-35%

Canadian Natural Gas Monthly Market Update, May, 2008 Natural Resources Canada

♦ Natural gas-fired generation will be significantly impacted by proposed carbon taxation - from the production and refining of natural gas, as well as the CO_2 produced from power generation.

♦ If Pickering B does not undergo refurbishment, the OPA has demonstrated that natural gas-fired generation will be utilized for the interim years until new nuclear resources come on line. It is

therefore evident that natural gas-fired generation will serve to provide baseload power in place of Pickering B. However, according to the OPA, "Gas-fired generation is not recommended for base-load generation because in that role it presents risks across all three dimensions of cost, environmental impact and financial risk." and "... the volatility of price and uncertainty of supply ... major drawbacks to gas-fired generation for base load." (Supply Mix Advice and Recommendations)
This deliberate use of natural gas-fired generation for baseload purposes is too costly, and violates the Ministerial Directive.

♦ Other comments from the OPA include:

▪ Natural gas-fired generation had a cost advantage in the 1990s based mainly on its relatively low capital and fuel costs, but today the fuel price has pushed up operating costs to eliminate that advantage."

▪ Key uncertainties for supply mix include unpredictability of future natural gas prices and availability..."

▪ "While it is impossible to quantify all of the risks at this point, the price and supply risk around gas as a generation source has grown significantly."

▪ "Do not use natural gas for base-load generation, since this use results in higher exposure to natural gas price risks."

Impacts of Natural Gas Generation on Electricity Prices

♦ North Side Energy, Consultant to the OPA regarding natural gas-fired generation in the IPSP, prepared May, 2008, indicates that "The increase in Ontario natural gas consumption associated with the IPSP is estimated to be relatively small and of short duration, suggesting that any effects on natural gas prices would be both minor and temporary." (EB 2007-07-07, Exhibit 1-12-34 Attachment 1)

If the increase in gas consumption for electricity generation is going to be so small, why do we need so much installed capacity, and why do we need 20 year contracts with so many private power generators?

The information provided by North Side Energy does not align with the following information:

- "The substantial increase in the hourly prices for electricity in 2005 is attributed to the increase in the price of natural gas following hurricanes Katrina and Rita, with those prices being 40 per cent higher in 2005 than in 2004. ... This also illustrates how in a market model, changes in fuel prices such as natural gas, a major component of the cost to produce electricity, have an immediate and direct impact on the price of electricity." (IESO - 2007 Market Outlook)

If the impact of less installed gas resources in 2005 had such an impact, imagine the impact that will happen when we double+ the installed capacity as primary market setting resources.

- "... electricity prices in Ontario dance very closely to the tune of natural gas. ... On average, a one percentage point increase in natural gas prices leads to 0.5 percentage point increase in electricity prices in Ontario." (CIBC World Markets Inc., July 18, 2007)

- "Where the province contracts for gas-fired generation under a commercial arrangement that is indexed to the price of natural gas, Ontario's electricity ratepayers are fully exposed to the volatility of natural gas prices." (Atomic Energy of Canada, Submission to the OPA, August 26, 2005)

- “Higher than forecast natural gas prices have been a primary contributor to higher than forecast electricity prices in the spot market. ... for every 10% increase in natural gas prices, Ontario electricity spot market prices would increase by approximately 6%.” (Navigant Consulting)

♦ The National Energy Board’s estimation of cost impacts includes the following comments:

(i) “From the standpoint of power generators using natural gas, however, they are still subject to price and supply risks associated with natural gas. Even if they have an RFP they are still subject to the risk of their plants not being competitive in the Ontario wholesale market. The nature of the risk is that a power generator has to decide if the anticipated power price will cover its costs, at least gas costs and other variable costs.”

(ii) “When gas generation set the price, it is more than twice as high (about $78/MW.h, versus about $33/MW.h for coal). It follows logically that increased gas-fired generation in Ontario will likely result in higher electricity prices due to greater frequency in setting the price of electricity, greater operational flexibility required in gas supply and services to serve the electric power generation sector, and the potential risks inherent with timing differences between gas and electricity markets.”

(iii) “Not only will electricity prices be influenced by that of natural gas but, with power generation becoming the fastest growing sector of natural gas demand, natural gas prices will also be increasingly influenced by electricity markets. This growing interdependency may contribute to higher costs for natural gas and electricity that will have to be absorbed by a range of energy consumers.”

(iv) “The growing share of electricity produced from natural gas will increasingly tie the price of the electricity to that of natural gas.”

(v)“… expectations of higher gas and electricity prices combined with the risk of diminished reliability raise the question as to whether there should be a debate or expanded discussion on the impacts of increasing the use of natural gas to generate electricity. Other consumers of gas, whether small residential and commercial customers or large industrials, may face higher energy costs as a greater portion of natural gas demand becomes increasingly weather sensitive. Further, some of these consumers may be challenged to compete with gas-fired generators for supplies of natural gas and related transportation services.”

♦ “North America’s natural gas market has entered a new era. Higher natural gas prices, which are now seen as a feature of the natural gas market, at least over the medium-term, primarily reflect the inability of North American natural gas production to keep pace with ever-increasing demand.” (Natural Resources Canada – Canadian Natural Gas Review of 2004, Outlook to 2020, January, 2006)

♦ "... natural gas has shifted from the ‘fuel of choice’ in North America to the ‘fuel of risk’ – from a plentiful, relatively inexpensive fuel to one marked by uncertainty, volatility and record price levels.” (CERA – Energy Research Oct. 2004)

♦ According to the U.S. government Energy Information Administration, natural gas prices 10 years from now will be “consistently higher” due to resource depletion and increased demand coupled with higher exploration and development costs. (Annual Energy Outlook 2006 with Projections to 2030)

♦ The average cost per unit of energy was over 3 times higher for natural gas than coal, over the 2002-2005 period. (US Energy Information Administration)

♦ Industry is warning that too much reliance on natural gas for electricity will cause irreparable harm to the Ontario economy. "The problem is particularly acute for industries relying on natural gas in their manufacturing process and as a fuel for electricity since they get hit twice by high natural gas prices." (New York Power Authority, Oct. 25, 2005)

♦ Consumers have expressed "An additional concern for price. ... not just the level of prices, but the rate which they change is a concern." (OPA Supply Mix Advice and Recommendations) Natural gas prices have, in recent years, been described as "volatile". ("changeable", "characterized by rapid change" - Webster) Volatility denotes rapid fluctuations in cost.

♦ "The price of gas in the long-term is linked to the price of oil and is highly volatile."

♦ "... if we consider the warnings that gas prices can be expected to be extremely volatile in the existing tight supply situation, then (Hurricane) Katrina is only a demonstration of how that volatility arises." (OPA Supply Mix Advice and Recommendations)

The cost of natural gas-fired generation is impacted by natural gas supplies which are declining.

Supply Concerns

Information supplied to the OPA indicates "...that natural gas supplies will be adequate to meet existing requirements and support growth in Canadian and U.S. markets without large increases in natural gas prices." (EB 2007-07-07, Exhibit 1-12-34 Attachment 1) The following information cautions otherwise.

All credible government and energy agencies, Canadian and international, confirm that North American natural gas production is in decline. Increasing demand for natural gas is now outpacing supply.

♦ The National Energy Board studied the use of natural gas for power generation in relevant parts of Canada and the U.S., with the conclusion that there will be increased competition for dwindling supplies, and that new resources in western Canada will not be sufficient to meet the growing needs. "the growing gas demand and uncertainty in future gas supply have meant high and volatile natural gas prices and have led to greater and renewed focus to develop other non-gas generation." (National Energy Board, "Natural Gas for Power Generation: Issues and Implications, June 2006

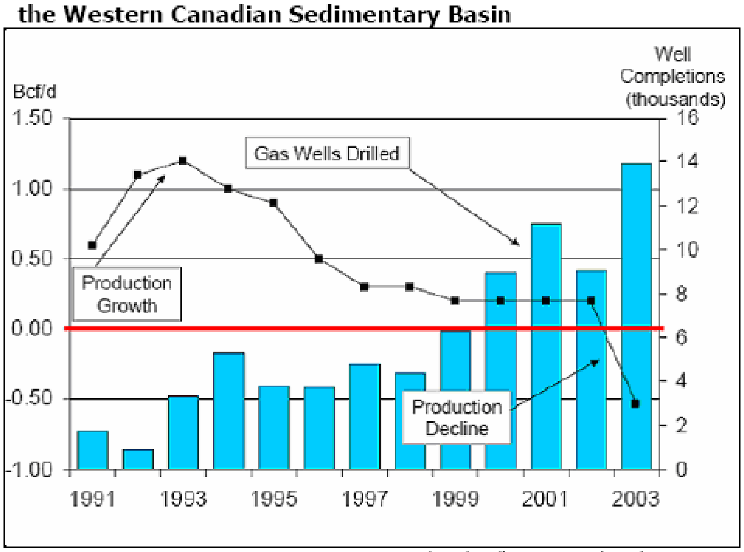
"High natural gas prices resulting from the tight balance between North American gas supply and demand has been a key factor in encouraging more gas drilling. … the producing sector needs to drill more wells each year just to keep production flat." (National Energy Board, "Natural Gas for Power Generation: Issues and Implications, June 2006")

♦ "By 2017, natural gas prices are expected to rise until 2020 due to depletion of conventional gas resources in the Western basin. These conventional resources will need to be replaced by more costly supplies from coal-bed methane and the Mackenzie Delta." (OPA Supply Resources Discussion Paper)

♦ The OPA reports that "More than 95% of the gas consumed in Ontario comes from outside the province, mostly from the WCSB". (Western Canadian Sedimentary Basin)

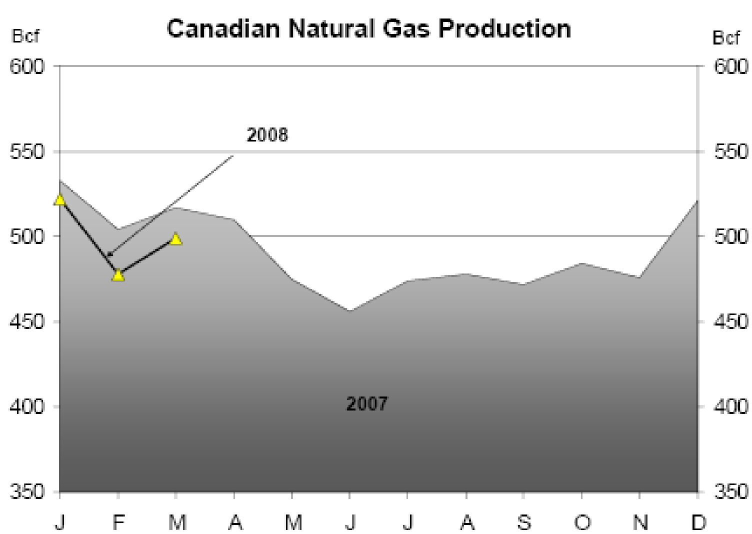
♦ The following chart demonstrates that record drilling is netting less natural gas production in the area where Ontario obtains most of its gas. "Total Canadian natural gas production declined 4% in 2003… almost 14,000 wells were drilled in the WCSB, setting a new record … average of over 38 wells per day." (Alberta produces 80% of Canadian natural gas from wells that are declining in production at a rate of 10-50% per year.)

Figure 3.9.4 – Production Change and Gas Wells Drilled on the Western Canadian Sedimentary Basin



Sources: StatsCan, CAPP, Daily Oil Bulletin, reproduced in NRCan

♦ Production increased slightly over the past year. However, "These production increases alone are not sufficient to meet the projected future requirements for natural gas demand, including power generation. Consequently, any increases in demand for gas-fired generation would necessitate a reduction in gas consumption by other consumers …" (National Energy Board, "Natural Gas for Power Generation: Issues and Implications, June 2006")



Source: Statistics Canada **Note:** Most recent month is a preliminary figure.

Canadian Natural Gas Monthly Market Update, May, 2008 Natural Resources Canada

♦ "While growing demand for gas in distant markets may increase flows on pipelines, greater consumption of natural gas in supply regions, such as associated cogeneration requirements by oil sands operations in western Canada, may reduce the amount of gas available for other markets and the flow on transmission pipelines." (National Energy Board, "Natural Gas for Power Generation: Issues and Implications)

♦ Recent National Energy Board (Canada) estimates suggest that nearly 2/3 of Canada's discovered resources have been consumed leaving only 7.5 years of proven reserves and another 5 years of possible reserves. British Petroleum estimates Canada's 2004 reserves to production ratio to be 8.8 years. BP's estimate for the United States' reserves to production ratio is only slightly higher at 9.8 years.

♦ "North America's natural gas market has entered a new era. Higher natural gas prices, which are now seen as a feature of the natural gas market, at least over the medium-term, primarily reflect the inability of North American natural gas production to keep pace with ever-increasing demand."
Natural Resources Canada – Canadian Natural Gas Review of 2004, Outlook to 2020, January, 2006

♦ The OPA has chosen to rely on resource supply estimates of the National Energy Board, 2004, which indicates, "... for the <u>ultimate potential</u> of natural gas in Canada, including proved reserves and undiscovered conventional resources (coalbed methane, tight and shale gas), 575 Tcf, which is about 77 years of natural gas at <u>2002 levels of production."</u>

♦ Total Canada (Tcf – Trillion Cubic Feet) (Canadian Petroleum Producers)

Proved Reserves (Jan 1/03)	59;
Discovered Resources:	151;
Undiscovered Resources:	365
Total Remaining Resources	**575**.

♦ Discovered Resources are "estimated quantities of gas in known drilled reservoirs, which are too remote to be connected to existing pipelines and markets. If pipelines were built, gas volumes would be recoverable under existing technological and economic conditions." Undiscovered Resources are "An estimate, inferred from geological data, of gas volumes thought to be recoverable ... but not yet discovered by drilling." These include "unconventional sources" of gas such as coalbed methane, shale and tight gas. (Natural Resources Canada, Review of 2004)

♦ The estimation of ... gas reserves is not an exact science. There is always uncertainty in making these predictions, ... To express the variance in reserves estimates, the industry has developed reserves classification systems, referred to as "Reserves Definitions". Proved, probable and possible reserves imply low, intermediate, and high degrees of uncertainty, respectively." (Reserves Estimations and Definitions: Standardization and Enforcement J. Glenn Robinson (Sproule Associates Limited)

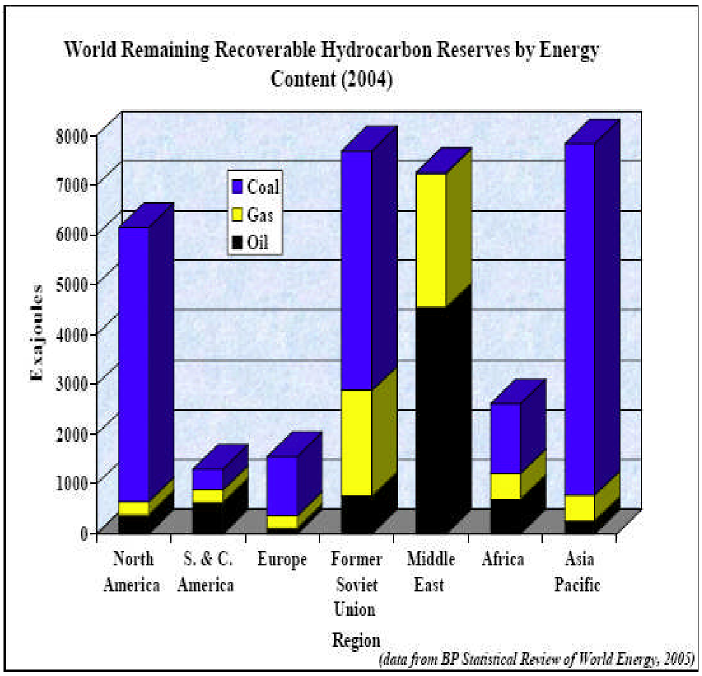
♦ The information upon which the OPA is making their recommendation is based on 2002 levels of production. However, Canadian production was down 4% in 2003 over 2002, although there was a 54% increase in drilling.

♦ "... by 2020, it is expected that western Canadian conventional natural gas production will be about 3 Tcf, accounting for only 10% of total North American natural gas supply. ... In Canada, total gas wells drilled increased 12%, surpassing the 15,600 well mark for the first time in history. ... exploration is now finding smaller and smaller pools..." (National Energy Board Canadian Natural Gas: Review of 2004 and Outlook to 2020)

♦ "At 60 trillion cubit feet, Canadian reserves... in 2002, giving a reserves/production ratio of 9.3 years. (CERI – World Energy: The Past and Possible Futures)

♦ "... the basis for the numbers is '2002 production' not consumption, which is higher than production now and growing. The key to how many years of supply are available in North America rests heavily on what is done to adjust consumption rates."

♦ ¾ of remaining natural gas resources are located in the former Soviet Union or the middle east. The following chart demonstrates the geopolitical concerns associated with countries where gas resources are more plentiful.



♦ As noted, conventional resources from the Alberta Basin will need to be replaced by supplies from coal-bed methane and from the Mackenzie Delta.

Coal-bed Methane

♦ According to the Alberta Chamber of Resources, "nobody knows the resource's true potential, or even how much gas is recoverable. … The Alberta Energy and Utilities Board estimate Alberta's reserves at 135 tcf to 410 tcf. …There are several uncertainties when trying to determine the amount of recoverable methane gas. Every CBM project is unique, and while some of the technology from the U.S. experience is helpful, the Canadian coal beds are typically less gassy and less porous, making it harder for the methane to flow to a well bore."

♦ "Speculation is that over the next five years Canada could see as many as 1000 CBM wells and the gas play could be as large as 1 billion cubic feet -- significantly less than the Canadian Gas Potential Committee's estimates of up to 486 tcf leading some to speculate that CBM will not offset North America's dwindling natural gas reserves in any significant way." (Alberta Chamber of Resources)

♦ “The geological and technical risks are huge and make CBM production a capital-intensive proposition on par with Alberta’s mega-project oil sands developments.” (Alberta Chamber of Resources)

♦ The National Energy Board indicates that “… still significant uncertainty surrounding the future of CBM development … The Horseshoe Canyon play in south-central Alberta was described as an example where developments have been positive. Ultimately some 50,000 wells may be needed to recover the CBM from this area alone.” (Looking Ahead to 2010 – Natural Gas Markets in Transition – An Energy Market Assessments, August, 2004)

♦ The Ontario Power Authority must consider the environmental impacts of coal bed methane when determining the sustainability of natural gas use in Ontario. There are serious issues surrounding both the dispersion of dirty water, as well as concerns associated with the large volumes of water produced from the coal seams. Although CBM production in Canada has been a “drier” process to date, drilling has recently begun in areas that will incur greater water concerns, similar to those experienced in the U.S.

<u>Mackenzie Delta</u>

♦ “The Mackenzie Valley Pipeline would bring about 0.80 to 1.5 billion cubic feet per day (Bcf/d) of natural gas from the Mackenzie Delta to pipeline connections in Alberta, which connect to the North American market.” (“North America The Energy Picture II - North American Energy Working Group - Security and Prosperity Partnership - Energy Picture Experts Group - January 2006”)

(The CAE Alliance has reviewed the National Energy Board report, “Natural Gas for Power Generation: Issues and Implications, June 2006”. All quotes in the following section regarding natural gas supply and cost are taken from this document, unless otherwise noted.)

♦ Ontario currently uses an average 2.7 Bcf of natural gas – about 2 Bcf/d in summer to over 4 Bcf/d during winter, about 10% of this is for electricity generation. A significant amount, over 3 Bcf/d, of natural gas piped and stored in Ontario is destined for other areas downstream.

♦ “The Board estimates the range for the incremental natural gas requirement in Ontario will be of about 8 to 20 million m3/d (0.3 to 0.7 Bcf/d) by 2010”, depending on the amount of nuclear to be considered in the mix. This was assuming about 2,550 MW of new gas generation in Ontario. At the time the NEB document was prepared, the Board assumption was that most of the coal replacement and new generation required in Ontario would come from nuclear, renewables and CDM. It is obvious that at least double that estimation of natural gas will be required, and that any new resources from the Mackenzie Delta are insufficient to supply Ontario’s needs.

♦ What must also be considered is the growing competition for the declining natural gas supplies in Alberta. For example, industrial demand in Alberta averages 1.5 Bcf/d - primarily accounted for by the high demand for natural gas at the oil sands projects, which are expected to continue to grow further. “… natural gas-fired cogeneration facilities are being developed in conjunction with the growing number of oil sands and in situ bitumen projects. As a result, Alberta has experienced the largest growth in gas-fired electricity generation capacity in Canada. In 2004, about 40 percent of installed electricity generation capacity in Alberta was natural gas-fired.”

♦ A large portion of the natural gas used in British Columbia and the U.S. Pacific Northwest comes from the WCSB. Gas demand, particularly in California, is expected to increase significantly for both electricity generation and industrial use. Approximately 25% of California gas comes from the WCSB. Lower hydro electric output and growing population is causing higher demand for electricity. Over 9,000 MW of natural gas fired generation is planned for California and Oregon. "All of these new developments will exacerbate natural gas demand."

Liquefied Natural Gas (LNG)

♦ Ontario will rely increasingly on LNG to mitigate both supply and price concerns.

♦ "Under these market conditions, Liquefied Natural Gas (LNG) is expected to play a critical role in addressing the forecast supply gas. ... future natural gas prices will be significantly influenced by LNG project development and this represents a major long-term gas price risk." (Navigant Consulting – commissioned by the OPA)

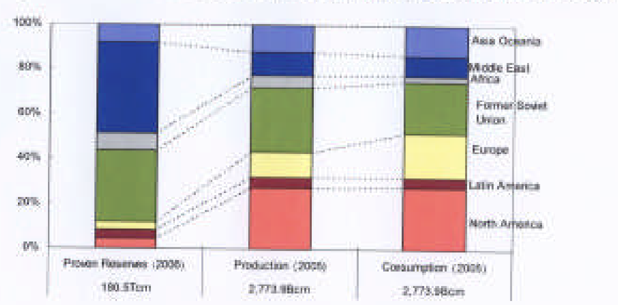
♦ Future LNG supplies to North America are the swing factor for future pricing. Those predicting lower and stable prices for the next 20 years anticipate significant LNG imports. However, "... much of the viable gas production exists in countries that are not politically friendly with the United States."("Clogs in the Pipeline"– May 16, 2005 - Navigant Consulting)

[Chart 1] World Natural Gas Reserves, Production and Consumption

	Proven Reserves (2006)		Production (2005)		Consumption (2005)	
	(Tcm)	Share (%)	(Bcm)	Share (%)	(Bcm)	Share (%)
North America	7.6	4.2%	752.1	27.1	769.5	27.7
Latin America	7.0	3.9%	128.3	4.6	114.3	4.1
Europe	6.6	3.7%	322.3	11.6	552.1	19.9
Former Soviet Union	57.2	31.8%	791.3	28.5	633.1	22.8
Africa	14.4	8.0%	152.7	5.5	79.6	2.9
Middle East	73.0	40.6%	288.8	10.4	250.8	9.0
Asia Oceania	14.7	8.1%	338.4	12.2	374.4	13.5
Total	180.5	100.3%	2,773.9	100.0	2,773.9	100.0

(Source) *Natural Gas in the World*, Cedigaz

[Chart 2] World Natural Gas Reserves, Production, and Consumption by Region



(Source) *Natural Gas in the World*, Cedigaz

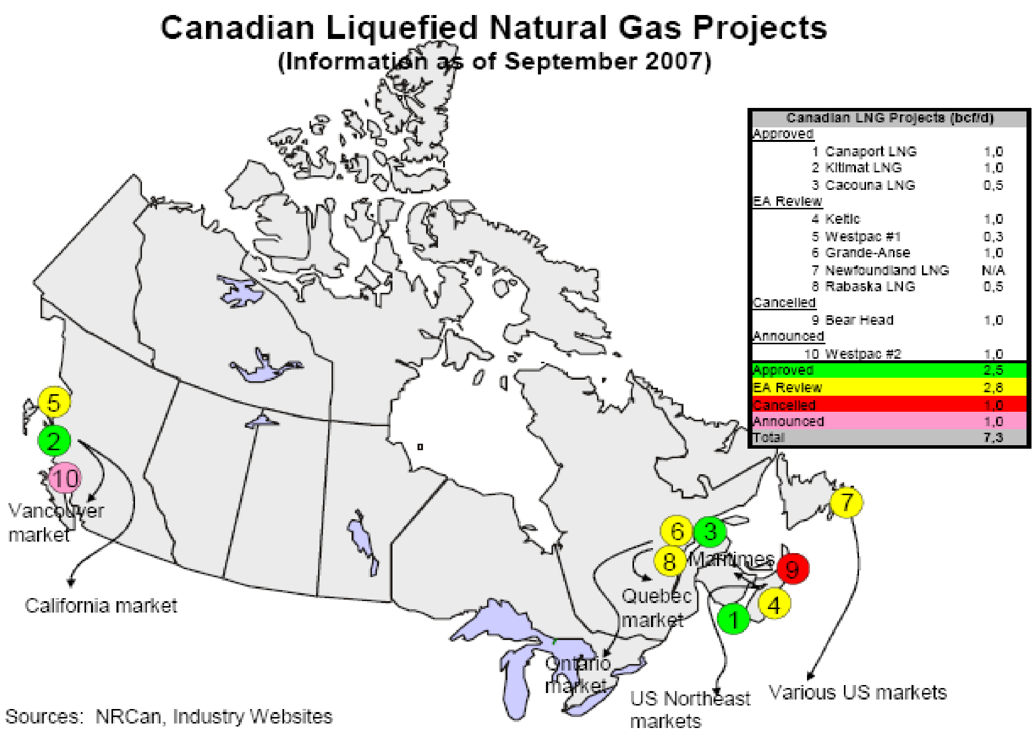
♦ Note however, the following from the US Dept of Energy, EIA website, March 13/08

The Lower 48 States continued to receive a relatively low level of imports of liquefied natural gas (LNG). LNG imports so far this month are about 44 percent below the level of last year. This reduction in supplies also is contributing upward pressure on prices ... The reduction in U.S. LNG imports reflects changes in LNG supply and demand across the world. LNG cargoes are heading to Europe and Asia, where buyers continue to purchase LNG at much higher prices than have prevailed in U.S. markets."

♦ The EIA Short Term Energy Outlook, February, 2008 also notes, "... a downward revision due to the expectation of continued demand strength in Asia and Western Europe, which compete with the United States for marginal LNG supplies and uncertainty about supply projects set to come on line..."

♦ Equally telling is the information regarding LNG proposals for Canada. According to Natural Resources Canada, "conventional reservoirs and producing areas of western Canada and the United States ... are maturing and high drilling rates are required to maintain production at current levels. Meanwhile demand for natural gas continues to be robust. ... new sources of natural gas supply, including increased LNG imports will be required." (Canadian LNG Import Projects: Status as of September, 2007) Supplies to eastern Canada are destined for local and U.S. markets.
Of the 10 projects highlighted, one has already been cancelled due to "an inability to sign a contract for LNG supply". A second, expected to supply natural gas to Ontario is "essentially dead", as the Russian supplier has since pulled out of this venture (Feb 08).

♦ Global energy is expected to rise by 60% over the next 20 years. The current global energy market is $3 Trillion/year. Reliance on LNG supply is risky at best and will become increasingly more costly. Further, the environmental implications have not been assessed as an option for Ontario generation.



Other Supply Concerns

♦ The National Energy Board studied the use of natural gas for power generation in the eastern part of Canada, and in relation to U.S., with the conclusion that , "For the U.S. Northeast, during the period 2000–2004, over 20,000 MW of generation capacity was installed with over 80 percent of that capable of using natural gas." As a result, "the growing gas demand and uncertainty in future gas supply have meant high and volatile natural gas prices and have led to greater and renewed focus to develop other non-gas generation." LNG is expected to play a role in lessening some of these concerns, "However, there are significant challenges with respect to the large investment required, uncertainty of supply, environmental impact and siting/acceptance of facilities."
The future impact of this on Ontario, other than the obvious natural gas supply concerns, is that portions of the U.S. Northeast may contract for hydroelectric imports from Quebec and Labrador which Ontario may be banking on to assist us in the middle to late years of the next decade.

♦ The National Energy Board also considered the implications of increased natural gas fired generation in the central geographical region. Findings include:

(i) "The EIA projects that gas demand … for the central region, including Ontario and the U.S. Midwest, are projected to range from 2.8 to 3.4 Bcf/d over the next decade.
The implications of this extend beyond simply having available gas infrastructure and supply capable of providing those additional volumes to the central region. While the region may have adequate pipeline infrastructure to access natural gas supplies, much of the existing supply and infrastructure is currently used to meet requirements in surrounding regions. With demand in the eastern region also projected to increase by more than 1.3 Bcf/d over the same period, competition and requirement for new gas supply and infrastructure will likely increase over the next several years."

(ii) "… the pattern of gas consumption for power generation will become much more weather sensitive and will present a gas load profile with more frequent and substantial variation than would be experienced from many of the traditional industrial gas consumers … especially in locations where natural gas-fired generation facilities become a significant part of the overall gas requirement and are expected to provide the swing or the load-following capability in electricity supply. This may also be exacerbated somewhat where refurbished nuclear facilities may provide more of the base load power generation, leaving natural gas facilities to provide the variable load-following supply of electricity." This will be the case in Ontario.

(iii) "Replacing electricity that is currently supplied from the approximately 7,500 MW of coal-fired generation in Ontario will have significant implications on future gas and electricity … Significant weather-induced variation in gas requirement is to be expected, especially considering the large percentage of homes currently using natural gas and electricity in Ontario. New gas-fired generation will likely exacerbate swings in gas demand and increase requirements on gas infrastructure and operations to meet fluctuating loads." (7,500 MW includes Lakeview Generating Station)

(iv) "According to the IESO, Ontario's future generation supply mix will place increasing value on the reliability that may be provided from generating assets with flexibility to provide load-following capability, operating reserve and generation control. For gas-fired generation to fulfill this function, gas services from storage and pipelines must also be provided to enable corresponding load-following requirements for natural gas."

♦ Enbridge Gas owns Canada's largest natural gas utility and provides natural gas to 18 million residential, commercial and industrial consumers across Ontario. The following quote represents this company's concern regarding gas supplies.
"Increasing demand for natural gas and a dearth of new supply from Western Canada means Ontario residents could be heating their homes in part with gas imported from offshore within five years, says Enbridge Inc. Chief executive Patrick Daniel told reporters that there is a 'real scramble' in the West to keep up with demand, and shorter supplies are looming. .... 'I don't think we need to be overly concerned about a shortage that would create inability to provide basic services ... But it would be at a price the consumer would find very high." ("Enbridge Scrambling to Meet Gas Demand" Toronto Star, May 6, 2004)
Enbridge is a partner in the Gaz Metro LNG Project, Beaumont Quebec. The facility is expected to be in service by mid 2010. A recent contract has been negotiated with Russian Gazprom to supply LNG to eastern Canada, describing Ontario and Quebec as "attractive markets" for natural gas. This supply will come at higher cost to Ontario natural gas consumers.

The CAE Alliance challenges the wisdom of reliance on significant new installation of natural gas fired generation considering the dwindling supplies of traditional sources of natural gas and uncertain expectation of newer and unconventional sources. Security of electricity supply will be dependent on natural gas resources in areas of the world that are politically unstable. We are staking our future on something that may not exist or materialize.

Replacement for Coal-Fired Generation

20. Does the IPSP 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?

(additional information answering this Issue can be found on pages 7-9, and on pages 28-45)

The OPA has been directed, through existing legislation, to provide a coal replacement strategy in conjuction with the energy experts of the IESO, and within the legislated perameters of electricity reliability, and adequacy. Although a Regulation has been passed mandating a coal closure time table - which we believe puts unrealistic constraints on the planning process - the OPA must nonetheless follow the Ministerial Directive to plan for the replacement of coal-fired generation without impacting system reliability.

(i) "Cleaner Sources"

♦ Although coal-fired generation will be displaced in part by cleaner sources of electricity production, such as wind, solar and hydroelectric, these resources will be insufficient to replace the hours of power generation and the generating characteristics of coal-fired power that are necessary for system security and cost moderation.

♦ "Economic imports, as modeled in the IPSP, will flow into Ontario if they are available to displace higher cost Ontario generation. Since some (but not all) of the coal replacement resources will have higher operating costs than coal, the number of hours in which imports can economically displace Ontario resources and thereby improve economics will be increased. The likely sources of import generation in the period 2008 to 2014 will be Manitoba and Québec (hydroelectric), Minnesota and Michigan (coal), and New York (gas)." (OPA Response to PWU- emphasis added)

♦ "... it could be reasonably expected that in view of the supply mixes of these jurisdictions (and particularly Minnesota), sources of imports could include all or some of hydroelectric, coal, nuclear and natural gas-fired resources." (OPA response to NOMA)

♦ Imports factor into system reliability and are included as a contingency resource. Imports will be generated from coal-fired facilities in other jurisdictions that are less environmentally "clean" than Ontario coal plants.

♦ The OPA has recommended citing new gas plants in Northern York Region, Kitchener- Waterloo-Cambridge-Guelph and Southwest GTA Regions, in addition to the already-committed 2,278 MW of natural gas-fired generation for the GTA area (Portlands, Goreway, Greenfield South Mississauga and Halton Hills). Although the OPA acknowledges that higher ozone will occur as a result of using gas-fired generation, there has been no assessment of the cumulative impacts of this 5,000 MW of gas-fired generation in the GTA airshed, particularly when the ambient air quality of the GTA is taken into consideration. As it is probable that gas-fired generation will be utilized more in the summer during times of poorer ambient air quality, this is an item of environmental concern.

♦ The OPA has not completed an environmental assessment of the impacts of natural gas-fired generation on a day to day basis, as units are ramped up and down, impacts of cold starts of units and the impacts of gas-fired turbines operating at low load. At lower loads emissions rise and may not meet Ontario regulation. NOx emissions increase because the units operate at regular, not low NOx burners. The information provided in the IPSP represents gas-fired facilities operating at maximum potential, fully loaded.

♦ The government's cost benefit analysis for coal closure indicates that Nanticoke Generating Station does not significantly impact the GTA air shed. Modeling results during smog season indicate that "…the Toronto ozone level from the Ontario coal plants is only 0.03 ppb". That is less than 1%. (Ontario's Cost-Benefit Analysis - Replacing Ontario's Coal-Fired Electricity Generation)

♦ The OPA indicates that "from an environmental standpoint, the implementation of the replacement resources are considered to result in lower air emissions, lower GHG, lower water use and lower amounts of waste compared to coal-fired resources. ..." (Response to PWU) However, the SENES report used by the OPA ignored some criteria, including life cycle GHG emissions of natural gas; the environmental impacts (air quality and GHG emissions) of unconventional sources of natural gas including LNG (liquefied natural gas); and the once through use of water resources for combined and single cycle natural-gas facilities.

♦ The OPA has allowed for fuel oil use in new natural gas-fired facilities. "In developing a balanced generation portfolio to minimize fuel supply vulnerability, consideration should be given to providing dual fuel capability at plants which are unable to maintain fuel inventories onsite. In particular, this aspect may be necessary for some new gas-fired plants to ensure operational capability during winter peak periods when gas demand and electricity demand peak simultaneously." (Supply Mix Advice and Recommendations)
Although Lennox Generating Station currently relies on oil for part of its electricity production, there is no discussion about the environmental impact of oil use, with the exception of SENES' review which rates oil higher than coal for environmental impacts.
This has not been considered, or factored into the environmental impact analysis.

♦ The Minister(s) of Energy have refused to consider the application of best available emissions reduction technology on existing coal-fired units that would reduce the emissions of greatest concern near par with those of natural gas. See Appendix "B" for an assessment of actual contribution of coal-fired generation to air contaminant emissions, and the reductions that could be achieved.

Greenhouse Gas (GHG) Reduction

Contrary to the perception implied by Ministry of Energy information, the closure of coal fired generation in Ontario will not create drastic, nor significant reductions in greenhouse gas emissions.

♦ The following chart, demonstrates the dramatic increase in installed capacity of natural gas fired resources (along with the decreased use of Lennox GS beginning in 2011). The gas-fired power production is estimated to double during the next 15-20 years. However, as we have noted earlier in this document, it is probable that natural gas will be utilized much more - an additional 5-33 TWh.

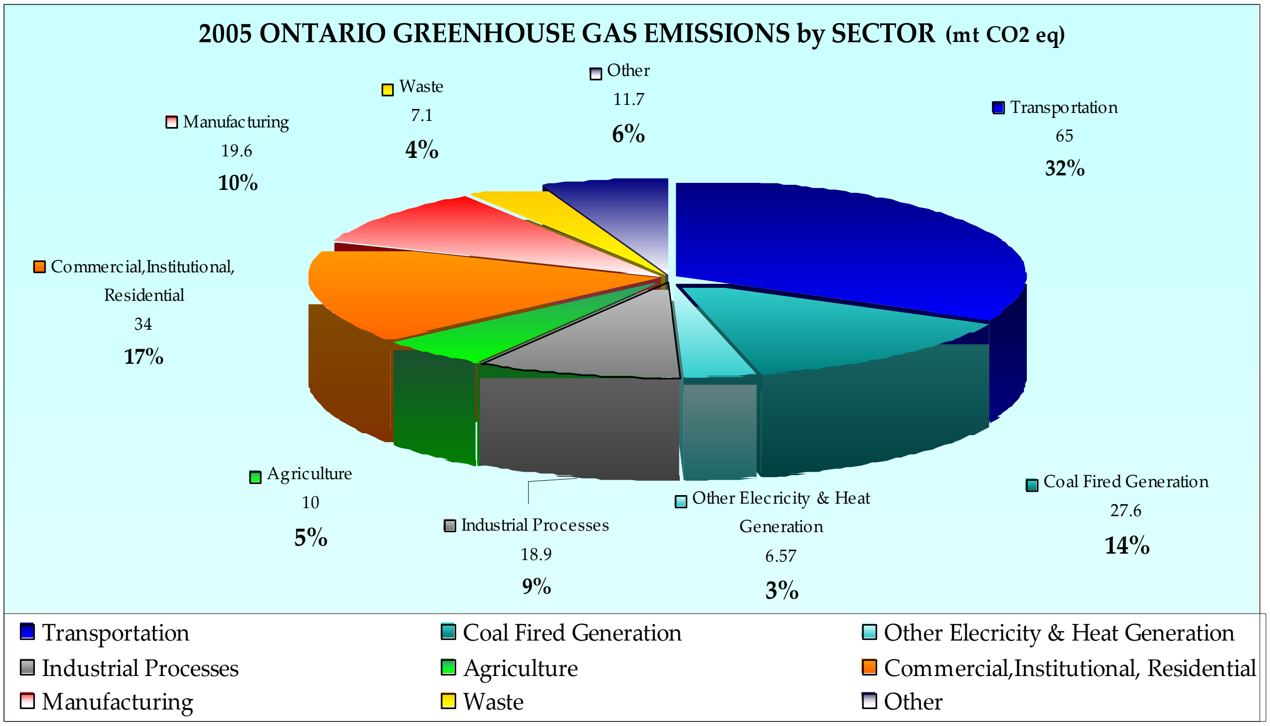
Table 5: Resource Contributions in the Absence of Coal-fired Resources but Including Regional Gas-fired Generation for Local Area Reliability and Lennox (MW)

Effective MW	2007	2008	2009	2010	2011	2012	2013	2014
Existing Nuclear	11,419	11,419	11,419	9,879	9,879	9,879	9,363	9,363
Committed Nuclear	0	0	0	1,500	1,500	2,270	3,040	3,040
Planned Nuclear	0	0	0	0	0	0	0	0
Existing Gas/Oil	4,578	4,578	4,578	4,578	2,473	2,473	2,308	2,308
Committed Gas	0	281	3,431	4,267	4,267	4,267	4,267	4,267
Planned Gas	0	0	0	0	2,455	2,905	4,507	5,057
Existing Renewables	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129
Committed Renewables	4	115	317	408	408	408	408	408
Planned Renewables	11	25	58	58	303	584	742	982
Committed Conservation	768	1,019	1,388	1,420	1,420	1,420	1,420	1,420
Planned Conservation	0	0	0	755	1,084	1,413	1,741	2,070
Interconnection	500	500	500	500	500	500	500	500
Total Available Resources	23,409	24,066	27,820	29,495	30,419	32,248	34,425	35,544
Annual Peak	26,282	26,515	26,749	26,986	27,205	27,426	27,648	27,873
Required Reserves	4,468	4,507	4,547	4,588	4,625	4,662	4,700	4,738
Required Resources	30,750	31,022	31,296	31,573	31,830	32,088	32,349	32,611
Gap (Required - Available)	7,341	6,956	3,477	2,079	1,411	0	0	0

Source: OPA

(IPSP - Replacing Coal-Fired Resources - Exhibit D, Tab 7, Schedule 1)

♦ Ontario's coal fired power plants presently contribute about 3% to Canada's total greenhouse gas emissions; 12% to total Ontario greenhouse gas emissions, down from the 14% of total provincial greenhouse gas emissions in 2005, as shown on the following chart. The 2005 contribution of CO_2 eq GHG from coal-fired generation was 27,290 kt; in 2006 that number was reduced to 24,000 kt CO_2 eq.



Environment Canada, National Inventory Report, 1990-2004 – Greenhouse Gas Sources and Sinks in Canada – Annex 12: Provincial/Territorial Greenhouse Gas Emission Tables, 1990-2005"
2005 includes Lakeview GS prior to closure

♦ Natural gas emits about 55% - 63% the CO_2 of coal generation **at point of combustion**. (63.06% according to - "Carbon Dioxide Emissions from the Generation of Electric Power in the United States", July 2000, staff of the U.S. Department of Energy and the U.S. Environmental Protection Agency; 56.67% according to Natural Resources Canada).

Therefore, replacing coal fired generation with natural gas would reduce total Ontario greenhouse gas emissions by only 5.4% (i.e. reducing the 12% contribution from coal-fired generation to Ontario's total emissions by 45%).

♦ However, this figure represents emissions from the power generation process alone. There are additional, significant emissions associated with production, flaring, processing and transport of natural gas. A life cycle assessment of methane (unburned natural gas), which is 23 times more potent as a greenhouse gas than CO_2 - from extraction through the pipeline, valves, fittings, compressor stations to power generation - would nulify the benefit of natural gas useage over coal.

♦ "Exploration, production, transmission and distribution of natural gas account for a quarter of the total emissions from the natural gas sector." (Canadian Gas Association, House of Commons Committee on Environment and Sustainable Development, February, 2007) These emissions are credited primarily to Alberta.

♦ "…. Contrary to its clean image, natural gas contributes to climate change. Although burning natural gas produces fewer greenhouse gas emissions than coal or oil (25–40% lower, per unit of generated electricity), natural gas still creates emissions when it is produced, processed, and transported…" (Suzuki Foundation submission to the Ontario Power Authority, Fall, 2005)

♦ "Burning gas instead of coal also sounds good and green since it cuts CO_2 emissions in half. In practice it may be the most dangerous energy source of all, because natural gas is 23 times as potent a greenhouse gas as CO_2. … even a 2 percent leak of the natural gas from the production sites to the power stations makes it as bad as burning coal. In practice, the leak rate is 4 percent, so it may be more than twice as bad as burning coal or oil." (Professor James Lovelock - address to the Canadian Nuclear Association Annual Seminar, March 10, 2005)

♦ The World Energy Council, of which Canada is a member (Energy Council of Canada), reports that "If life cycle analysis was used and other greenhouse gases were taken into account, electricity generation from fuels other than coal would show similar or even higher GHG emissions. ... the projected increase in annual emissions of carbon dioxide from coal between 2001 and 2025 of 1.1 billion metric tons of carbon equivalent will be less than the increased amount for either natural gas (1.3 billion tons) or oil (1.5 billion tons)."

♦ Fugitive releases (e.g. venting and flaring from oil production, methane leaks from pipelines) by themselves contributed to greenhouse gas emissions. The current estimates show an increase of 24.1 Mt between 1990 and 2006, a growth of about 57%. Much of this increase is the result of higher crude oil and natural gas exports. (Environment Canada)

♦ Greenhouse gas emissions (2006) associated with natural gas delivery and storage within Ontario alone were 3.61 kt CO_2 equ (3,609,358 tonnes CO2 – Enbridge Gas Distribution Inc.; Union Gas re: natural gas distribution and transmission systems; and TransCanada Pipeline System, Ontario - Environment Canada) This will rise signficantly when the new infrastructure facilities for additional gas storage and transport of gas for power generation is installed.

♦ When lifecycle emissions are taken into consideration, natural gas GHG emissions are about 25% less than coal. (IAEA Spadaro et al. 2000). This gap could be closed by burning biomass with coal.

♦"If life cycle analysis was used and other greenhouse gases were taken into account, electricity generation from fuels other than coal would show similar or even higher GHG emissions …" (World Energy Council)

♦ "In Canada … natural gas is a larger source of carbon dioxide emissions than coal. Natural gas 29.7%; Coal 18.6% (Carbon Dioxide Fact Sheet, 2007)

♦ Considering the significant amount of new gas fired generation proposed for Ontario, and the future supply concerns, "…liquefied Natural Gas (LNG) is expected to play a critical role in addressing the forecast supply gap." (Navigant Consulting Report to OPA) There are greenhouse gas implications of using LNG. LNG entails an energy loss of 15% - 30% in the transport, liquefaction and regasification processes.

♦ The OPA has not taken into consideration the carbon intensity of generating facilities. Some existing natural gas fired power plants produce higher emissions/MWh.

♦ The Ontario government has recently joined the Western Climate Initiative. The proposals for GHG reductions include a target of 15% below 2005 levels by 2020. This initiatve also includes "tail pipe standards for vehicles". This reduction has already taken place with regard to coal-fired generation. As shown on the chart on page 48, transportation accounts for 32% of Ontario ghgs and should be the target of reductions.

Table A9–7: Electricity Generation and GHG Emission Details for Ontario[1]

Sources	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006[6]
	Greenhouse Gas Emissions[5] *kt CO2 equivalent*																
Coal	24,740	26,170	25,390	16,500	13,530	14,250	16,360	20,520	27,150	28,230	36,160	33,300	33,110	32,870	24,460	27,290	24,000
Refined Petroleum Products[2]	1,130	910	680	110	220	250	220	320	1,100	1,000	350	610	440	1,080	690	40	30
Natural Gas	0	0	740	1,160	1,610	2,940	2,730	3,460	3,690	4,850	4,610	5,300	5,380	5,630	4,810	5,660	4,430
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hydro[3]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Biomass[4]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Renewables	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	0	0	0	0	0	10	10	110	40	40	20	0	50	10	0	0	0
Overall Total	25,870	27,090	26,810	17,770	15,350	17,450	19,330	24,400	31,990	34,130	41,140	39,210	38,980	39,590	29,950	32,980	28,460

♦ Some new natural gas fired power plants in Ontario will utilize both oil and natural gas for power production. Some will be single cycle peaking plants. The emissions associated with both these forms of power production are higher than combined cycle natural gas plants.

♦ The reduction of coal fired power use will necessite the equivalent of 24.7 TWhs of production from other sources. The net value of conservation and renewable energy will barely cover the increase in load demand. It is probable that power will be imported from coal fired power plants in the U.S. While this may reduce Ontario contributions to greenhouse gas emissions, it will create higher emissions elsewhere in Canada (process and transport of natural gas from western provinces), internationally (emissions associated with liquefied natural gas), or to the U.S. from "dirtier" coal facilities.

♦ According to the (Independent Electricity System Operator) IESO, market resources (both internal generators and imports) will continue to be selected in cost based merit order. (May 30,2008) According to the U.S. government Energy Information Administration (EIA), the average retail price for electricity generated in Michigan was 8.44 cents/kWh; in Ohio 7.65 cents/kWh, compared to the average Ontario electricity spot market price in 2007 of 5.1 cents/kWh. With coal fired generation setting market price in Ontario 55% of the time, prices have been moderated. When coal is replaced with natural gas generation, at almost triple the cost (at current prices), imports will become more economical and chosen by the IESO in cost based order prior to Ontario natural gas facilities. (But Ontario consumers will still have to pay a guaranteed return to gas fired plants)
This will have environmental ramifications.

Table 2: Energy Production from Coal-fired Facilities (TWh)

Station	2003	2004	2005	2006
Lambton	10.6	7.7	9.4	6.9
Nanticoke	20.4	14.5	17.7	16.2
Thunder Bay	1.5	1.0	1.0	1.0
Atikokan	1.0	1.0	1.0	0.7
Lakeview	2.8	2.3	0.7	0.0
Total	**36.3**	**26.4**	**29.7**	**24.7**
% of Actual Ontario Annual Energy	**23.9**	**17.2**	**18.9**	**16.3**

Source: OPG, IESO
Note: The Lakeview station was shut down in 2005 and taken out of service

♦ The OPA has been directed to plan to replace coal-fired generation "by cleaner sources in the earliest practical time frame". Co-firing of biomass with coal at existing facilities could be accomplished within the time frame, thereby reducing GHG emissions likely on par with natural gas-fired generation if the life cycle emissions of natural gas were taken into consideration.

<u>(ii) "Earliest Practical Timeframe"</u>

♦ Although the OPA has the legislated mandate to fulfill this requirement, the Ministry of Energy has forced a timetable by implementing the carbon cap and coal closure regulation. The CAE Alliance maintains that this Regulation and amendments has interfered with the legal requirements of the OPA and the OEB under the Electricity Act, and in particular the requirements for preparation and review of the IPSP. (See submission to the EBR, available from our website)

♦ The CAE Alliance believes that the legal requirements to “plan for coal-fired generation in Ontario to be replaced by cleaner sources in the earliest practical time frames that ensures adequate generating capacity and electricity system reliability in Ontario.” and to "work closely with the IESO (Independent Electricity System Operator) 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” is still the priority for the OPA.

♦ The IESO is carefully monitoring replacement generation. “As project commitments are made by the OPA … the Ontario Reliability Outlook will monitor and report on infrastructure developments and their impact on future reliability.” (IESO, The Ontario Reliability Outlook, March, 2007)
The coal closure is not an isolated aspect of electricity restructuring in Ontario. Removal of these facilities has major impacts on the system as a whole. Unlike wind and solar, they provide 24/7 resource availability. Unlike baseload nuclear, they provide quick dispatch load following capability, vital to system reliability."

♦ The OPA is planning significant natural gas-fired generation to replace coal. However, it has been noted that "of the planned resources to be procured, the gas-fired generation resources may face acquisition risks concerning: timing of approvals; availability of project components; and availability of construction resources....". These uncertainties impact the 2014 timeline as the earliest practical.

<u>(iii) "Adequate Generating Capacity"</u>

♦ The OPA notes that "the coal-fired resources will provide two roles during the coal replacement plan period to 2014: ensuring that electricity requirements in Ontario are met; and, providing an insurance role to mitigate risks associated with the implementation and performance of all coal replacement resources. ..."

♦ According to the OPA, "... the capacity gap from 2012 to 2015 will be filled by planned gas-fired resources consisting of new gas-fired generation located in areas with local reliability needs and Lennox. This still leaves a capacity gap to 2012 which requires the existing installed coal-fired resources to continue to operate combined with reliance on interconnections as the only feasible alternative." ... "Risks considered include uncertainties associated with the development of Conservation resources, renewable resources, gas-fired resources, and nuclear resources, and nuclear performance. The results of the risk analysis determined the amount of generation required to mitigate the risks and to provide the necessary insurance. This insurance function is necessary in order to ensure the reliability of the electricity system. Coal-fired generation and interconnections are the only feasible resources that can provide this insurance function to 2014."

However, the OPA has not advised what measures Ontario Power Generation (OPG) has taken to ensure staffing levels are satisfactory for plant performance. It is reasonable to assume that employees will seek work elsewhere once it is evident that coal plant output will be reduced. The OPA has not advised whether fuel supply for the coal plants will be available for provision of this "insurance role".

(iv) System Reliability

♦ In addition to the concerns highlighted in the first section of this document, there are concerns regarding gas infrastructure and supply to proposed gas-fired facilities that impact system reliability. The OPA has not provided stakeholders with assurances that firm supplies for gas delivery are in place, stating that contractual details are outside of both the OEB jurisdiction, and the public review. However, in view of the volume of gas generation anticipated, and the importance of the role it will provide in system reliability, it is imperative that gas supply issues be openly addressed.

♦ “Coal-fired generators currently play an important role in responding to load changes that occur during five-minute intervals throughout the day. The largest load change typically occurs during the morning pick-up period, and is about 60-70 MW per minute, at times totaling more than 3,000 MW an hour, with periods of sustained increase or decrease lasting for up to four hours or more. ... Ontario gas-fired generators typically offer load following capability over the upper 25% of their capacity range, whereas coal-fired units can typically achieve load following from minimum load up to maximum output, which represents the upper 80% of each unit’s capacity range.” (IESO – Highlights of 10-Year Outlook, Jan/06-Dec/15)

♦ “Ontario Power Generation raised the concern that when new gas-fired power generation is added to the Province’s generation portfolio, the amount of load-following capability available in the market will decline. This decline will exacerbate the current problem with generators that are capable of ramping up and down. ...” (Ontario Energy Board – Natural Gas Electricity Interface Review)

♦ “...the aggregate of the new replacement resources must closely resemble the overall energy capability of existing coal-fired generating stations to ensure that energy is available to serve load with the same level of reliability.” (IESO 10-Year Outlook Highlights, Jan/06-Dec/15)

♦ “There must be minimum load following (ramping) capability provided by the resource mix to be able to match supply with demand on a real-time basis. Currently the largest load pick up period is in the order to 3,000 to 3,500 MW/hr or 60 to 70 MW/min.” (IESO Submission to the OPA)

♦ The CAE Alliance has continuing concerns regarding load following capability. Intervenor questions posed to the OPA were not sufficiently addressed. References to the IESO's report are not reassuring. "The IESO balances supply and demand through its direction of dispatchable resources, which will continue throughout the on-going evolution of Ontario’s generating fleet. Although this report indicates, at least on an hourly basis, that there is sufficient flexibility to successfully operate using the proposed resources mix, challenges remain. Load following capability on a more granular level than hourly blocks of time is required if the proposed resource mix is to achieve true operability. Figure 1 shows the gradual increase in the proportion of generation outside the dispatch control of the IESO or normally unavailable for dispatch and a corresponding decrease in dispatchable generation able to respond to 5-minute dispatch. (www.ieso.ca/imoweb/pubs/ircp/IESO-Operability_Review_of_IPSP.pdf)

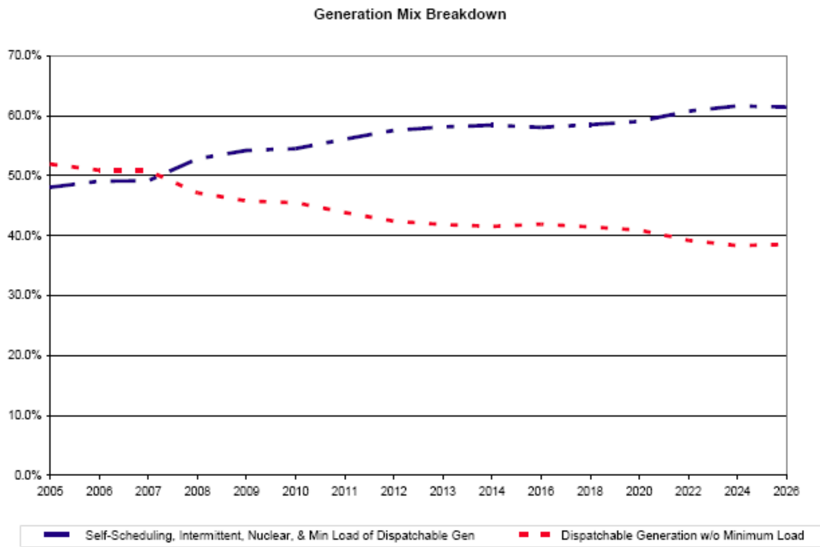


Figure 1: Generation Availability for Dispatch

♦ According to the OPA, "Coal-fired generation would continue to provide insurance until the end of 2014 under the high load-growth cases. Beyond 2014, additional resources would be required. These additional requirements after 2014 are met with 1,200 MW of resources in 2016 growing to over 5,000 MW by 2027, including 3,000 MW of additional (for now) unspecified resources by 2027 as well as about 2,000 MW of additional natural gas-fired resources (relative to the cases developed for reference load conditions)". (EB-2007-0707 Exhibit G Tab 1 Schedule 1 Page 3 of 50)

The information provided in the IPSP does not alleviate concerns that the volume and distribution of natural gas will be available for the additional gas-fired resources.

♦ When questioned about comparison of natural gas-fired and coal-fired resource abilities to provide timely load following response to sudden changes in load requirements, the OPA responded "Both gas-fired and coal-fired generation facilities are flexible and fairly responsive resources to meet various load-following requirements. The main differences are associated with their load-following capability relative to their capacity range, with coal-fired units generally covering a larger unit capacity range compared to gas-fired units." (Response to Canadian Manufacturers and Exporters)
Rather than fully develop this answer, the OPA again referred to the IESO Operability Review, which, as noted earlier, does not address this question.

♦ "The hourly data provided by the OPA did not allow an explicit analysis of the 5-minute dispatch effect on the future flexible generation pool. It is reasonable to assume that dispatch volatility is unlikely to reduce from current levels, in the absence of any further mitigation. For example, throughout the study period, in 20% of the hours, hydroelectric generation volumes changed by more than 500 MW. As slower moving thermal and gas units try to respond to these changes, other fast-moving resources must ramp to make up the difference, exposing them to significant dispatch volatility. The IESO recognizes stakeholder concerns in this area and has implemented various programs to mitigate the dispatch volatility of load following units, but concerns remain. In order to maintain the availability rate of the dispatchable resources presented in the IPSP, the IESO and its stakeholders must continue to address the impact of dispatch issues on flexible generation."

♦ The OPA used an EFOR rating of 5% throughout the planning period, based on "the historical and forecast performance of certain technologies as well as input from the IESO. The 5% forecast forced outage rate for gas is also noted by the IESO in D-2-1, Attachment 1, Table 4, page 12 which states 'These forecast outage rates are consistent with IESO short-term data for mature operating units'." (Response to PWU)
The OPA has not conducted an assessment of the impact of Ontario's load demand profile on new natural gas-fired generation to determine how and when these facilities will operate, the impact of load following on critical plant components, etc. It is highly likely that there will higher outages which will impact system reliability.

♦ The OPA has noted that "Our analysis relies on interconnections for meeting extreme weather conditions." (Supply Mix Advice and Recommendations)

♦ For reliability of electricity supply, adequate resources and sufficient margin are imperative, sufficient to sustain extreme weather conditions. "If we were going to rely heavily on Manitoba and Quebec water power, the risk of common drought needs to be considered and appropriately mitigated. Regional coincidence of gas supply shortages may be another area where our risk and the risk of our neighbours are the same." Fuel shortages "may apply to new gas-fired generation during winter peak periods when gas demand and electricity demand peak simultaneously." (IESO)

♦"Ontario will now have its peak demands in the same season as the major adjacent markets, with the exception of Quebec. We cannot assume that they will be available to make up Ontario's shortfalls when we experience extreme temperatures." (IESO)

21. How do existing, committed and planned conservation initiatives, renewable resources and nuclear power contribute to meeting the contribution that coal-fired generation currently provides to meeting Ontario's electricity needs with respect to capacity (6,434 MW), energy production (24.7 TWh) and reliability (flexibility, dispatchability, and the ability to respond to unforeseen supply availability)?

The OPA acknowledges coal fired generation to be "an important component of the present supply mix … supporting the security of the electricity system and in helping to manage uncertainties caused by the unavailability and/or reduced capacity of other generating plants. ... Coal-fired generation is a flexible, dispatchable and quick response supply resource, and supports the reliability of the Ontario electricity system. Flexibility is particularly important to respond to commonly occurring supply unavailability and hour-to-hour load following (ramping) requirements. ... also helps to maintain supply reliability to local areas."

♦ The inclusion of some renewables and nuclear facilities will reduce some of the production from coal-fired facilities, but will increase the need for load following capability. "… the IESO continues to identify a need to ensure that the future supply and demand response mix has sufficient generation that can be dispatched up or down to match changes in the level of demand. … critical during early morning hours, when demand climbs quickly and in the evening when demand begins to decline. Over half of Ontario's installed capacity … are baseload or non-maneuverable generation … This type of capacity is expected to grow over the next few years with the addition of 1,500 MW of Bruce A generation and significant amounts of new wind generation." (IESO, The Ontario Reliability Outlook, March, 2007)

♦ “Wind, solar and some small hydroelectric generation provide power when and if certain natural events occur, which gives them a somewhat unpredictable output. ... require additional generation to ramp up faster, a requirement that can add costs.” (OPA Supply Mix)

♦ It is impossible, at this point in time, to replace coal fired generation with anything but another fossil fuel. Wind and solar can displace, but due to generating characteristics, cannot replace. Nuclear power is suitable for base load. The 24.5 TWh of coal fired power produced in 2006 cannot be offset by the most ambitious combination of conservation, wind, solar and remaining hydro capability.

♦ As has been noted, the inclusion of renewables will increase the occasions of surplus baseload power. This will increase the need for resources (coal or natural gas) to supply power if nuclear units are forced off line.

♦ "There is approximately 500 MW of currently installed wind capacity. As the size of the wind fleet increases as shown by the data in the IPSP, the IESO will have to consider its impact on flexible generation and the need for additional intra-hour load following services."(IESO as above)

♦ The planned hydroelectric resources will not contribute much in terms of intermediate, load following generation.

22. What are the remaining requirements in all of these areas?

It is evident that the characteristics of coal-fired generation that impact system reliability cannot be replaced with CDM and renewables. It is questionable whether the proposed mix of natural gas resources (CCGT, SCGT and CHP) can adequately meet these system needs.

23. Will the IPSP’s combination of gas and transmission resources meet these remaining requirements in the earliest practical timeframe and in a manner that is economically prudent and cost effective?

From the information provided throughout this submission, the CAE Alliance believes that implementing natural gas-fired generation to replace coal fired power is not economically prudent, nor cost effective.

♦ "Natural gas-fired generation is only considered suitable for local area reliability requirements only where there are no other suitable options." In other words, gas-fired generation will be procured regardless of cost if it is what it takes to remove coal fired generation.

♦ The OPA has noted several conditions that are necessary to achieve the Plan's gas-fired generation capacity and the associated timelines. These include:

Sufficient gas infrastructure and commodity availability;
Availability of critical components and resources to develop, construct and operate facilities;
Effective commercial arrangements; (explained by way of Interrogatory response as "proponents to cost effectively develop and maintain the ability for gas-fired generation to provide the capacity and energy required in the Plan");
Timely project approvals and continuing financial viability of the projects; and
Continued requirement for heat by accessible steam hosts, and the ability of the CHP projects to produce heat at a competitive price.
(EB 2007-0707 Exhibit D, Tab 8, Schedule 1)

♦ In response to the concerns listed above, it must be noted that:

Questions posed to the OPA requesting confirmation of the ability of gas generators to secure firm gas supplies. OPA denied that information, citing confidentiality of contracts.

Information provided regarding required gas infrastructure and supply indicates that "most", but not all will be in place to supply the procured gas generation, but not the future planned generation, nor the contingency additions of gas fired power that will likely be required.

"Of the planned resources to be procured, the gas-fired generation resources may face acquisition risks concerning: timing of approvals; availability of project components; and availability of construction resources...." (OPA)

With natural gas costs continuing to escalate, it is quite possible that CHP heat production will not be competitively priced.

In order to comply with the Ministerial Directive the OPA is forced to procure significant natural gas generation, although that is not a prudent alternative or option from either a reliability or cost perspective.

♦ The interim measures being proposed to deliver supply from the Bruce would seem to introduce perhaps an undue level of risk to the entire system. Discussion paper 5 states “that these interim measures are acceptable only as a stop-gap measure since they introduce an increased level of complexity (risk?) to a critical part of Ontario’s network and the neighboring interconnect systems”.

Consultation with non-Aboriginal Interests in Developing the IPSP

27. Has the OPA, in developing the IPSP, consulted 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?

"Affordable and reliable supplies of electricity have long powered the Ontario economy and the modern lifestyles enjoyed by the more than 12 million people who call the province home. ... electricity plays such an important role in our economic health, and exciting because we have the opportunity to reshape our electrical power system to be more economic and environmentally sustainable. ... The plans and decisions we make now will have a profound impact for many decades to come. For that reason, the Ontario Power Authority (OPA) is strongly encouraging Ontario's consumers, businesses and other stakeholders to become involved in the planning process." (OPA Supply Resources Discussion Paper)

In spite of this statement, the OPA has not fulfilled the responsibility to consult with consumers.

♦ There has been insufficient interaction with the general public - the residential consumer impacted by the electricity plan. The public meetings held to discuss the initial supply mix advice and recommendations was poorly advertised. (CAE Alliance arranged for additional local advertising in the Sarnia-Lambton area, at cost to our organization to encourage the public to attend.) OPA staff were unprepared for the questions addressed by the public and had insufficient knowledge of the material they were there to represent.

♦ The OPA claims to be "strongly encouraging" stakeholder involvement in the planning process. However, there has been only 1 series of public meetings - poorly advertised, during the summer months - on the most important power initiatives in 20 years.

"The advertisement on the IPSP was part of a larger communications effort that included a province-wide media advisory (June 27, 2006), a news release (June 29, 2006), a special open web-enabled teleconference (June 29, 2006) and the advertisement which ran only on July 11, 2006. All were designed to help stakeholders understand the IPSP process and provide opportunities for input. The selection of the eight provincial and community newspapers was based on broad coverage throughout the province as well as targeted to specific local areas in which local area reliability needs were identified, in order to provide notice of the initiation of consultation on the IPSP. The purpose of the advertisement was to engage the interest of potential participants to the consultation process and direct them to the website for more information and the schedule of events."

♦ The OPA has indicated that the government directive "very much shapes the plan … is prescriptive, with the areas where there is OPA discretion being relatively narrow." As a result, many public concerns were dismissed because of non-conformity to government policy.

♦ Although the OPA indicates that "Stakeholder engagement is a valuable and integral component of the process to develop the IPSP." Representation of stakeholder interest seems to come primarily from power producers and from environmental groups that have an unrealistic assessment of the scientific and economic challenges in the power market.

♦ The OPA commissioned a study of the public stakeholder for feedback (Decision Partners). Over 90% of research respondents indicated reliability and availability of electricity as top priority. "... environmental responsibility was ... rated high or medium by almost all of the interviewees ... but throughout ... interviewees spoke more about availability of electricity and the economic impacts than they did environmental impacts ..." .

♦ Public survey consultant Decision Partners has reported to the OPA that, "Most participants … concluded that in the end, the Ontario economy must be the most important priority – the economy is the primary driver of all decisions in the Province."

♦ "Public opinion research conducted for the supply mix advice showed that in Ontario, as elsewhere, reliability of supply is the most important concern. Reliability is an important consideration and is reflected in the OPA's planning criteria, as is cost effectiveness." (Response to AMPCO)
The CAE Alliance maintains that the public concerns regarding reliability and cost impacts of the power plan are being ignored in order to fulfill aspects of the Ministerial Directive.

♦ Societal acceptance", a component of sustainability, is impacted by information given to the public by the media and public interest groups which are considered "most believable". (Decision Partners, December, 2005) The government and government agencies are not as trusted to provide credible information. Unfortunately, much of the information generated for the public is not an accurate representation of the energy and resource situation, and much is geared to justify political policy. The OPA has committed to "openness, transparency and accountability".

♦ The people of Ontario have a legislated right to participate in government decisions regarding energy policy. It is therefore imperative that the public be given sufficient and full information regarding the power plan impacts from an environmental and an economic perspective. Any government information that misinforms, misleads or otherwise impairs a proper understanding of issues violates that public right.

♦ The CAE Alliance has met with policy advisors from the Ministry of the Environment and the Ministry of Energy. Letters and questions were directed to the Ministers from both of these ministries. Although we were promised answers to our queries and concerns, none materialized. Staff from these ministries encouraged the CAE Alliance to direct our efforts toward involvement with the OPA Planning process. In response to our continued questions, OPA advised, "We don't make policy, we just follow it." Some of our questions directed to the OPA were not addressed nor answered.

Environmental Issues in Developing the IPSP

31. Has the OPA, in developing the IPSP, ensured that safety, environmental protection and environmental sustainability are considered?

The OPA has not fulfilled this planning criteria.

♦ The CAE Alliance maintains that the environmental analysis is skewed to favour predetermined resource selection. The OPA did not bring an unbiased mindset to the determination of environmental criteria. Some important aspects were not included, while others had an artificially high rank. Changes, inaccuracies or omissions in any one category will impact the overall rating of a resource and therefore the viability/suitability of inclusion in the supply mix.

SENES, the consulting firm commissioned to assess environmental impacts, used a system of "power scorecard" to compare generation sources. This method was utilized to identify and quantify relevant environmental factors, cumulative impacts and sustainability for generation options and supply mix plans. Impact rankings were used to determine overall analysis of the effects of each generation type to the environment. According to SENES, the "Power Scorecard" methodology is somewhat subjective, in that the "rankings of different generation technologies reflect the bias of the authors..." and "...The relative importance of one aspect of the environment versus another is largely a measure of societal values and/or politics ..."

Although the environmental assessment was deemed to have included "a life-cycle approach - from mining of raw fuel material to operations, and through decommissioning and waste disposal", the environmental impacts of the significant infrastructure changes - gas pipelines, gas storage and transmission lines - associated with the addition of large volumes of natural gas were not factored into the impacts assessment. "No information was readily available for any generation option or evaluation criteria" regarding the transport of natural gas. (SENES) However, fugitive emissions of methane are significant, up to 4% line losses in the transport of natural gas.

♦ The OPA notes that "Sustainability in Ontario's power system originates well before the creation of the OPA … the requirement for considering sustainability in the IPSP reflects a rich story in gradual and implicit policy development in Ontario. … the recent emphasis on sustainability in the electricity industry can be traced back to the all-party Select Committee on Alternate Fuels, which recommended in 2002 that coal-fired electricity generation in Ontario be replaced by 2015." (page 6 Sustainability)

This report indicates:

"The Committee believes that Ontario should work to eliminate its reliance upon coal based power generation, unless future technological advances result in dramatically reduced air emissions that are equivalent to or lower than emissions from natural gas generation." (page 19-20 Final Report)

"Oil and natural gas-fired generation should also be phased out." (page 20)

"ensure that the relative cost of different energy sources, fiscal implications, energy security, impact on job creation, export development and the provincial economy are all considered; and

The Ontario government shall use a 'Life Cycle Costing' approach to assess costs and impacts of new fuel/energy technologies. In assessing the costs of new alternative fuel/energy sources, comparisons should be made with the costs of new conventional sources of fuel/energy.

The OPA has chosen one statement to justify coal closure, without adherence to these other principles for resource selection.

♦ Regarding environmental sustainability, the OPA has not considered the cumulative impacts of water withdrawal on the Great Lakes in respect of natural gas-fired resources planned for the GTA, Kitchener Waterloo, and surrounding areas.

The calculation used by SENES for water withdrawal for a Natural gas/Oil, Combined Cycle Plant with Cooling tower is 874 litres/MWh, typical water consumption 684 litres/Mwh. However, the figures provided by Calpine Corp. for the Greenfield Energy Centre, a 1005 MW natural gas plant indicate 20,400 litres/minute, or 1,224,000 litres/hour. Comments from Calpine Corp. include, "Water intake from St. Clair River used for cooling purposes only ... 90% of cooling water evaporated; 10% treated and discharged back to river." Therefore, there is significantly more cumulative, consumptive use of water from the Great Lakes River system. Decreasing water levels are a concern for this waterway system. The installed capacity of gas-fired resources in the GTA/south central Ontario area is estimated to be approximately

♦ For further information regarding environmental assessment information used by the OPA, please refer to the CAE Alliance Response to the OPA Supply Mix Advice and Recommendations, included in the OPA filing of the IPSP.

32. Has the OPA, in developing the IPSP, ensured that for each electricity project recommended in the Plan that meets the criteria set out in subsection 2(2) of Regulation 424/04, the Plan contains a sound rationale including:

(a) an analysis of the impact on the environment of the electricity project; and

(b) an analysis of the impact on the environment of a reasonable range of alternatives to the electricity project?

♦ According to the Guide to EA Requirements for Electricity Projects, "Environment means: ...social, economic and cultural conditions that influence the life of man or a community" and "Negative environmental effects include the negative effects that a project has, or could potentially have, directly or indirectly on the environment at any stage in the project life cycle. ... Negative environmental effects may also include the displacement, impairment, conflict or interference with existing land uses, approved land use plans, business or economic enterprises, ... social conditions or economic structure." And elsewhere, "... neighbourhood or community character, local businesses, institutions, increases in the demands on community services and infrastructure, negative effects on the economic base of a municipality or community, negative effects on local employment"

The OPA has not completed an assessment of the impacts on the business, economic or economic base of the province, or of individual communities, of the significant use of natural gas-fired generation, or of the removal of coal fired power plants.

♦ The OPA did not consider the use of biomass in conjunction with coal-fired burning, which would reduce ghg emissions and would have the added benefit of enhancing our agricultural and forestry industries. This technology would reduce emissions from existing Ontario coal fired power plants to a level comparable with natural gas use.

♦ The OPA did not include an analysis of the impact on the environment of a reasonable range of alternatives to the electricity projects proposed. For example, the OPA did not consider the option of implementing full, best available emissions control technology on existing coal-fired generation units.

♦ A recent report completed by the University of Waterloo's Department of Chemistry compared the effects on air quality of coal and natural gas electricity generation. This study concludes that "... if currently existing remediation technology were used, the air quality effects from coal-fired power plants are comparable to those from natural gas plants and neither could be distinguished from the regional background at distances more than a few km from the source."

This study, funded in part by the Ontario Ministry of the Environment, reports that the 4 operating coal plants in Ontario contribute 3-4% of the total SO_2 and about 1-2% of the NO_X in southern Ontario, 10% and 8% respectively within 20 km of the largest facility. However, "currently existing remediation technology on the coal plant reduces both the SO_2 and NO_X contributions to about 0.3% when averaged across southern Ontario and about 1% within 20 km of the largest plant". ("A Regional Modeling Study of the Effects on Air Quality of Electric Power Generation by Fossil Fuels" Waterloo Centre for Atmospheric Sciences, May 26, 2006)

♦ The OPA has not conducted an analysis of the various natural-gas fired power plants to determine the impact on the social and economic structure of communities, and of the province. The OPA has not conducted an evaluation comparison of the environmental impacts of natural gas use to replace coal-fired generation on a day to day real time basis.

For further information, see Appendix B.

IPSP In General

34. Does the IPSP meet its obligation to provide adequate electricity system reliability in all regions of Ontario?

No. As noted in the OPA response to NOMA, "Although the OPA expects the planned and other resources to address the retirement of TB and Atikokan, the OPA recognizes that there are uncertainties with respect to how conditions unfold in the Northwest. These include: the extent, if any, of load recovery, uptake in Conservation programs, and results of OPA procurements (see Exhibit D-2-1, section 6). Accordingly, the OPA plans to very closely monitor conditions in the Northwest and investigate contingency plans."
This does not represent a solid plan to "provide adequate electricity system reliability" to this area of the province.

B. Procurement Processes

2. In developing its procurement processes, has the OPA complied with the following principles:

(a) Procurement processes and selection criteria must be fair and clearly stated and, wherever possible, open and accessible to a broad range of interested bidders;
(b) To the greatest extent possible, the procurement process must be a competitive process;
(c) There must be no conflicts of interest or unfair advantage allowed in the selection process; and
(d) 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 25.32(1) of the Electricity Act.

♦ In accordance with O. Reg. 426/04, “To the greatest extent possible, the procurement process must be a competitive process.” However, OPG has been disallowed from some of the competitive processes, in spite of the fact that publicly produced power has a cost advantage.

♦ The Board has the legislated responsibility to review the procurement processes for electricity supply. However, the government continues to direct the OPA regarding certain resource requirements, removing the procurement process outside of this mandate. For example, "... Northern York Region is not addressed because the OPA has been directed by the government to procure new gas-fired generation and therefore the OPA’s recommendation in this respect is no longer relevant to this proceeding." (Response to PWU) The OPA now advises that the government is directing the OPA to procure new gas-fired generation in the Southwest GTA, and it will therefore also be considered outside of this process. (Web conference, July 4, 2008)

The procurement process is taken, at will, out of the hands of the OPA and is, like most of the planning process, driven by Ministerial intervention.

Respectfully,
Carol Chudy
On behalf of
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APPENDIX "A"

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29 November 2007

Ontario Energy Board
PO Box 2319, 26th Floor
2300 Yonge Street
Toronto
Ontario
M4P 1E4

Attn Chris Cincar

Re: Ontario Energy Board Smart Price Pilot Report, July 2007

Dear Sir,

Having studied the impact of the Smart Meter program from a theoretical point of view, it was of great interest to me to read the results of the OEB Sponsored Smart Price Pilot Study (OSPP) conducted in Ottawa in 2006/2007.

I am concerned that the OSPP was quite limited in scope, there are omissions in the cost-benefit analysis and the conclusions are misleading and biased

Participation in the OSPP

While the participants were randomly selected from the Ottawa area they were not representative of the average population in Ontario. For example:

(a) 77% of the participants homes were built after 2001
(b) 83% of the participants were college/university graduates or higher.
(c) Less than 9% of the participants had a total income of less than $50,000 whereas Ontario overall has double this number earning less than $50,000. In fact 88% of participants incomes were in excess of $75,000 with 17% exceeding $150,000.

It is quite clear from this information that the participants were largely from the more educated and affluent segments of society.

Study Methodology

The study time period was only seven months, therefore the full impact of annual cycle is missing.

The study was based on evaluating the impact of different pricing structures on the group as a whole. This did not reveal the true impacts/hardships for different demographic groups such as low-income families and retirees versus mid and upper income working families. The normal load profiles for these groups are totally different.

Study Results

1. Economic results

(a). Load Shifting

The only statistically significant shift in load away from peak periods was measured during two critical peak days called in August.

The only other statistically significant load shifting evident by members of the three price groups during the five critical peak days in September or January was an ***increase*** in load on January 17. This confirms the difficulty of shifting load during the winter that was identified by the focus groups.

Load shifting away from the On-Peak period for all days in the pilot, not just critical peak days, was also analyzed. These results showed no applicable statistically significant load shifting from On-Peak periods as a result of the TOU price structure alone.

Minimal savings of an average of $1.44/month were identified as a result of load shifting.

(b). Conservation

During the study participants achieved far greater savings of $2.73/month by simply reducing consumption of electricity.

(c). Cost-Benefit

The “savings” claimed do not take into account the billions of dollars the smart meter program will cost. These costs will more than outweigh any savings claimed by this study.

2. Feedback from participants

Expected Bill Impact

“The impact on individual bills seemed to be less than many focus group participants had hoped. Few of the focus group participants felt they had realized “large” savings on their electricity bills. In fact, many focus group participants expressed disappointment that their efforts did not result in greater savings.” If this is how the participants felt, how would they feel if the full cost of the smart meter program was included??

APPENDIX "A"

Overall satisfaction

"The majority (78%) of survey respondents would recommend the time-of-use pricing plan to their friends, while only 6% would definitely not" This feedback is flawed since the cost for the smart meter program had not been considered.

"Respondents most frequently cited more awareness of how to reduce their bill, giving greater control over their electricity costs and environmental benefits as the top three reasons behind the satisfaction." This is an exaggeration of the facts, no doubt to make the results more "politically correct". 8 categories were used to rate satisfaction. Environmental Benefits were mentioned by only 52% of respondents and is shown in 6^{th} place, only ahead of "Other" or "None" each of which were mentioned by 1% of the participants. I.e. Environmental Benefits were the last of 6 reasons behind the satisfaction. (See table on page 54 of the Report.). To put these reasons in true perspective, the Table in Appendix G shows that only 1% of the participants gave the Environment as the top reason.

"Those not sure or who would not recommend the program cited insufficient potential savings and too much effort as the reasons why."

Conclusions

The OSPP confirmed the intuitively obvious; managing summer and winter peak loads are two different challenges. Air-conditioning is the key focus in the summer and consumers have some ability to respond to demand. In the winter there is little opportunity to load shift and conservation is the target. The Smart Meter Program (TOU) is a very expensive way to address these challenges and has marginal impact. There are more cost effective ways to meet these challenges without placing severe hardship on certain groups of the population.

TOU Pricing

If we believe the government's premise that the TOU Pricing Program is not a way of price-gouging, then the program would be a zero sum exercise. I.e. overall, the same amount of dollars would be collected from the consumers, but those using on peak supply would pay more and those using off peak supply would pay less. This is fine as an overall broad concept. However in reality, the poor, the sick and the conscientious all get penalized by this system and finish up subsidizing those who can really afford to pay.

As an example consider a retired couple who have bought all the energy efficient appliances they can and have cut back their consumption of electricity to the absolute minimum. For this couple to "stay whole" in the summer, they will have to simply cut back on what little air-conditioning they use since most of the electricity used would be at peak periods would be charged at 3 times the off peak rate, instead of the lowest tier in the current pricing system.

During the winter this couple would have no option for further load shifting or conservation other than eating sandwiches in the dark during the suppertime peak.

My studies show that high volume users of electricity, those with electric heating and large working families with children in school will benefit from TOU pricing at the expense of low volume stay at home users, even if they do nothing. The reason being the high volume users mentioned above can benefit from the entire weekend of off peak rates, whereas the low volume users do not have enough weekend demand to get the same advantage. This is an in justice and is morally wrong.

Recommendations

The Smart Meter Program should be suspended immediately until a true cost estimate and the impact it will have on consumer's bills is made public.

Alternate less costly ways of reducing peak demands should be evaluated. Consider methods that reward rather than penalize consumers who conserve reduce their overall consumption.

Since the summer peak is driven by air-conditioning demand, "a stick and carrot" approach could be used. Simply expanding the current summer pricing system by another tier or two would protect the low consumption customer and place the burden where it belongs, on the high consumption customer. This would only require a minor additional change to the billing system, which is changed twice per year already. This would soon get the attention of those who have massive homes and leave all their doors and windows open when running their air-conditioning. The technology to electronically turn off the air-conditioners of willing participants should be made widely available. This could be done on a rotating basis so that no one consumer has to off line for a prolonged period. An annual cost rebate should be applied to consumers bill for participating in such a program.

As the OSPP concluded, there is little room for load shifting during the winter peak; so overall conservation is the goal. Lighting is a major consumer of electricity in the winter and more incentives should be given to people to change out their light bulbs or buy more energy efficient appliances. The OPA's IPSP suggests that the smart meter program can reduce peak electricity demand by 176MW. Assuming an energy saving of 50W for each new low energy light bulb, this reduction in demand could be achieved by 3.52 million light bulbs. If the government gave these away at a cost of say $8 per bulb it would cost $28 million, a far cry from the $2+ billion for the Smart Meter Program. This is a guaranteed way of achieving the targeted reduction without the need for monitoring and follow up. Of course that would reduce the need to expand the bureaucratic empire of the Conservation Officer which might be unacceptable!

Yours truly,

Tom Hughes
President

APPENDIX "B"

ENVIRONMENTAL IMPACTS OF COAL-FIRED GENERATION

There has been a general misconception about the actual environmental impacts of coal-fired generation in Ontario, and about the mitigation measures that could be implemented to reduce contaminant emissions.

(i) An exaggeration of both health and environmental impacts of coal-fired generation in Ontario;

(ii) Emissions could economically and readily be reduced;

(iii) A comparison of replacement generation and the resultant net impact of transitioning to an alternative fossil fuel.

(i) An exaggeration of both health and environmental impacts of coal-fired generation in Ontario

Coal-fired generation in Ontario is responsible for less than 7% of air quality concerns. The health and environmental impacts stated are not in proportion to the emissions released. The coal plants meet or exceed all laws and regulations presently in place to protect the environment.

♦ The Ontario Medical Association indicates that health issues associated with pollution are attributable to **chronic** and **acute** exposure to **5** common pollutants, namely:

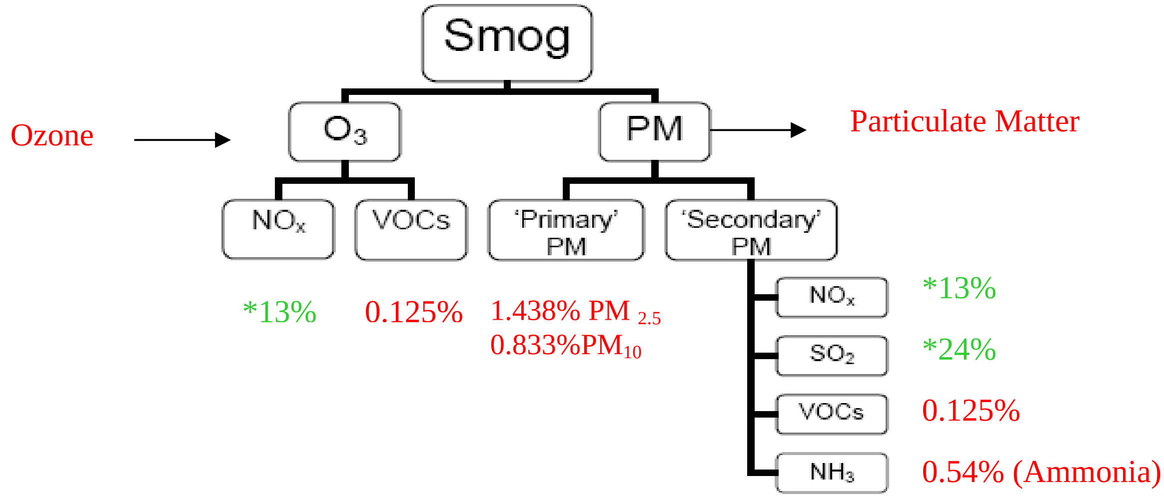
Ozone (O3) which is comprised of NOx (nitrogen oxides) + VOCs (volatile organic compounds); $PM_{2.5}$ (particulate matter); CO (carbon monoxide); and SO_2 (sulphur dioxide). (Ministry of the Environment)

♦ Ozone and fine particulate matter ($PM_{2.5}$), the major components of smog, continue to exceed the ambient air quality criteria and remain the pollutants of most concern. Emissions of NO_x, SO_2 and CO have decreased significantly over the past 35 years and do not exceed government criteria standards. (Ontario Ministry of The Environment, Air Quality in Ontario, 2005)

♦ Coal's contribution to the provincial emissions of the smog precursors, VOCs, and CO are less than 1%. Transportation is by far the greatest contributor.

♦ Coal fired generation in Ontario is responsible for 1.438% of provincial $PM_{2.5}$ and 0.833% of PM_{10} emissions. (Environment Canada)

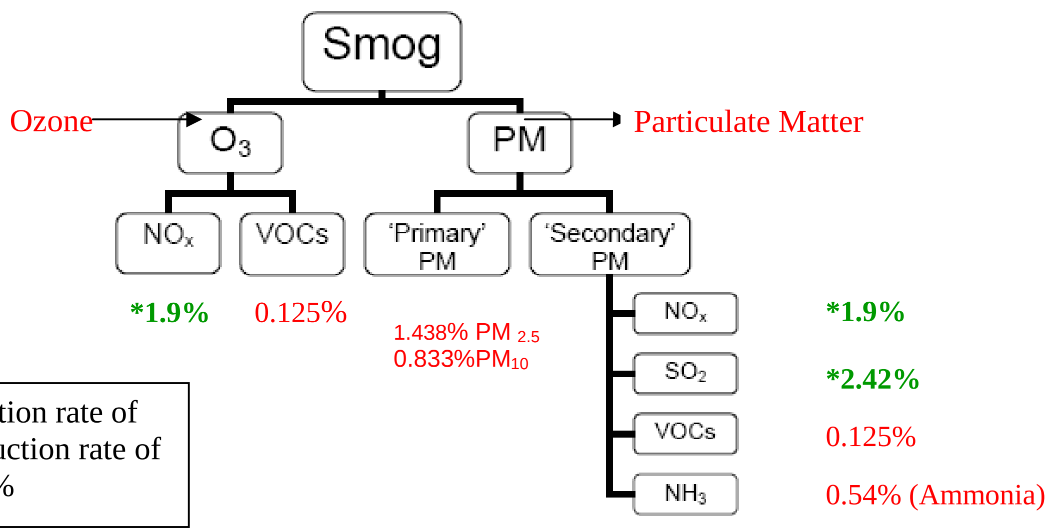
CONTRIBUTION OF COAL FIRED POWER GENERATION TO ONTARIO'S PORTION OF SMOG PRECURSORS



Environment Canada Air Contaminant Emissions tracking also includes CO (carbon monoxide). Coal-fired generation in Ontario contributes 0.49% to Ontario's portion of CO emissions

(These figures include Lakeview GS, now closed.)

CONTRIBUTION OF EMISSIONS FROM COAL-FIRED POWER PLANTS – **WITH POLLUTION ABATEMENT TECHNOLOGY**



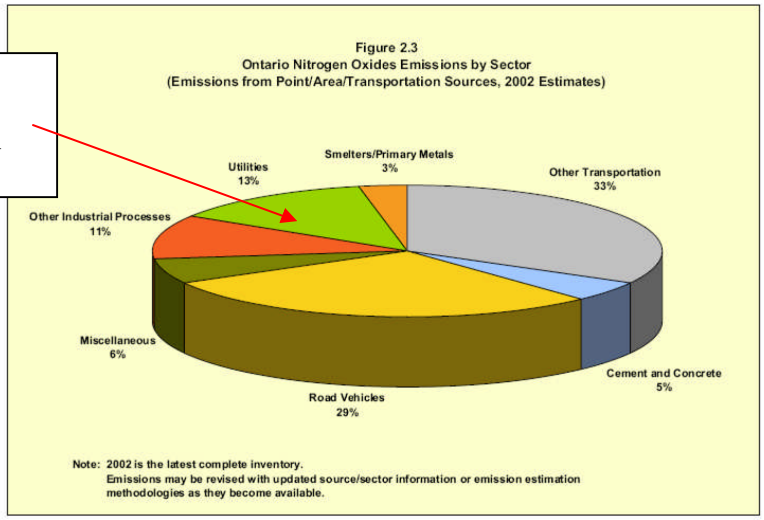
* NOx reduction rate of 85%; SO2 reduction rate of 90%

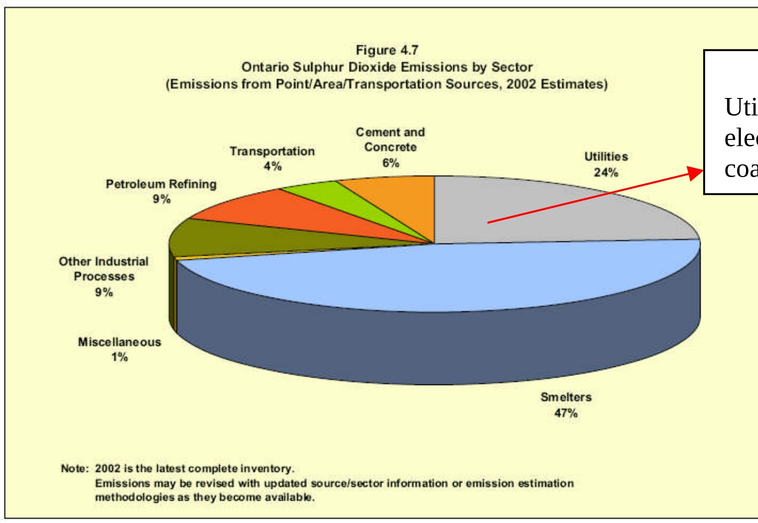
Particulate Matter can be reduced 99%; Mercury and other heavy metals can likewise be reduced 60%-90% (95% Mercury capture at Lambton GS Units 3 & 4)

(Sources: Ontario Ministry of the Environment – Ontario's Clean Air Action Plan: Protecting Environmental and Human Health in Ontario; Environment Canada – Criteria Air Contaminants Emission Summaries)

CONTRIBUTION OF ELECTRICITY GENERATION TO AIR QUALITY EMISSIONS IN ONTARIO

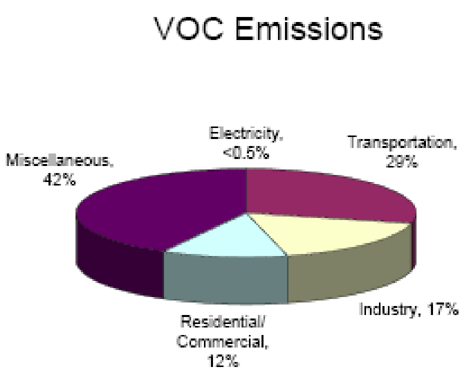
NOx
Utilities - 13% - Includes electricity generation from coal, natural gas and oil

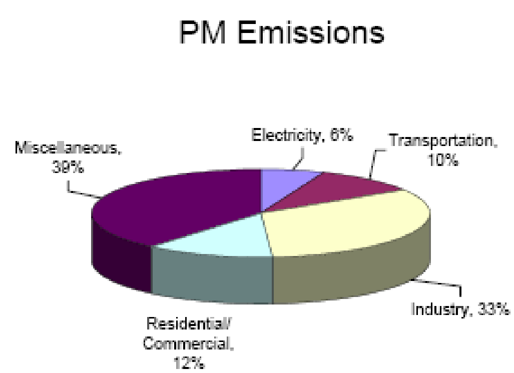




SO2
Utilities - 24% - Includes electricity generation from coal, natural gas and oil

(Ministry of the Environment, Air Quality in Ontario, 2005)





("Ontario's Clean Air Action Plan: Protecting Environmental and Human Health in Ontario", June 21, 2004 – Ontario Ministry of the Environment)

♦ Natural gas fired generation, which is being procured to replace coal fired power in Ontario, will be more harmful with regard to particulate matter. "Scientists point to the smaller particulates — those that measure less than 10 microns - and the smallest particulates - those that measure less than 2.5 microns - as being particularly of concern. These particulates can reach deep within the lung or can enter the bloodstream and cause damage throughout the body." (Ontario Clean Air Alliance)

A report prepared for the Ministry of Energy states that "The scientific evidence demonstrating that the $PM_{2.5}$ fraction accounts for many health damages has increased substantially over the last five years. Accordingly, health damages were forecast largely based on $PM_{2.5}$ concentrations."
This report also states that "All particulate from gas turbines is on the order of 1 micron, hence all PM is assumed to be $PM_{2.5}$." (natural gas combined cycle facilities)
(Cost Benefit Analysis: Replacing Ontario's Coal-Fired Electricity Generation, prepared for the Ministry of Energy, April 2005)

♦ Ozone concentrations in urban areas (i.e. GTA) are expected to worsen with the use of natural gas generation. (Cost Benefit Analysis: Replacing Ontario's Coal-Fired Electricity Generation) This is confirmed by the OPA.

♦ Coal fired generation contributes more significantly to SO_2 and NO_x emissions (24% and 13% respectively). However, when transborder air pollution, and background emissions are taken into consideration, the coal fired contribution is minimal.

♦ According to the Ministry of the Environment, 55% of Ontario's air contaminant emissions originate in the U.S. "Background" emissions, described as "natural and human sources from outside of North America, together with natural sources within North America", also contribute significantly to Ontario air quality.

For example, Ministry of the Environment information indicates that "Ontario's NOx emissions in the regional air shed … are about 6 % of the total NO_x emitted."
Canadian sources in the region "emit less than 10% of total sulphur dioxide (SO_2) and NO_x emissions."
and
"Ontario's SO_2 emissions account for approximately 6% of the combined total in the Ontario and neighbouring U.S. airshed."
(Transboundary, Air Pollution in Ontario, June 2005, Ministry of the Environment)

Coal fired generation therefore accounts for a net 2.4% and 1.3% respectively of total SO_2 and NO_x in the Ontario air shed. (24% and 13% of the Ontario portion which accounts for 10% of the total)

♦ This is confirmed by reports and studies, including a regional modeling study of the effects on air quality of electric power generation, conducted by the University of Waterloo Department of Chemistry, which concluded that **Ontario's 4 coal generation facilities contribute "about 3-4% of the total SO_2 and about 1-2% of the total NO_x in southern Ontario.** The contributions rise to about 10% and 8% respectively within 20 km of the largest facility." (ie Nanticoke). ("A Regional Modeling Study of the Effects on Air Quality of Electric Power Generation by Fossil Fuels" Waterloo Centre for Atmospheric Sciences, May 26, 2006)

IMPACT OF TRANSBORDER AIR FLOW ON ONTARIO AIR QUALITY

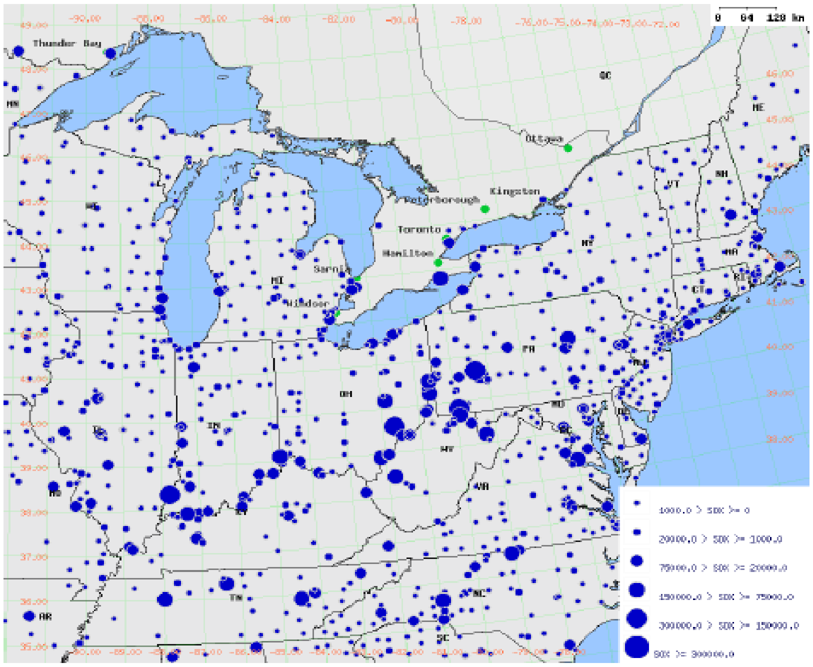
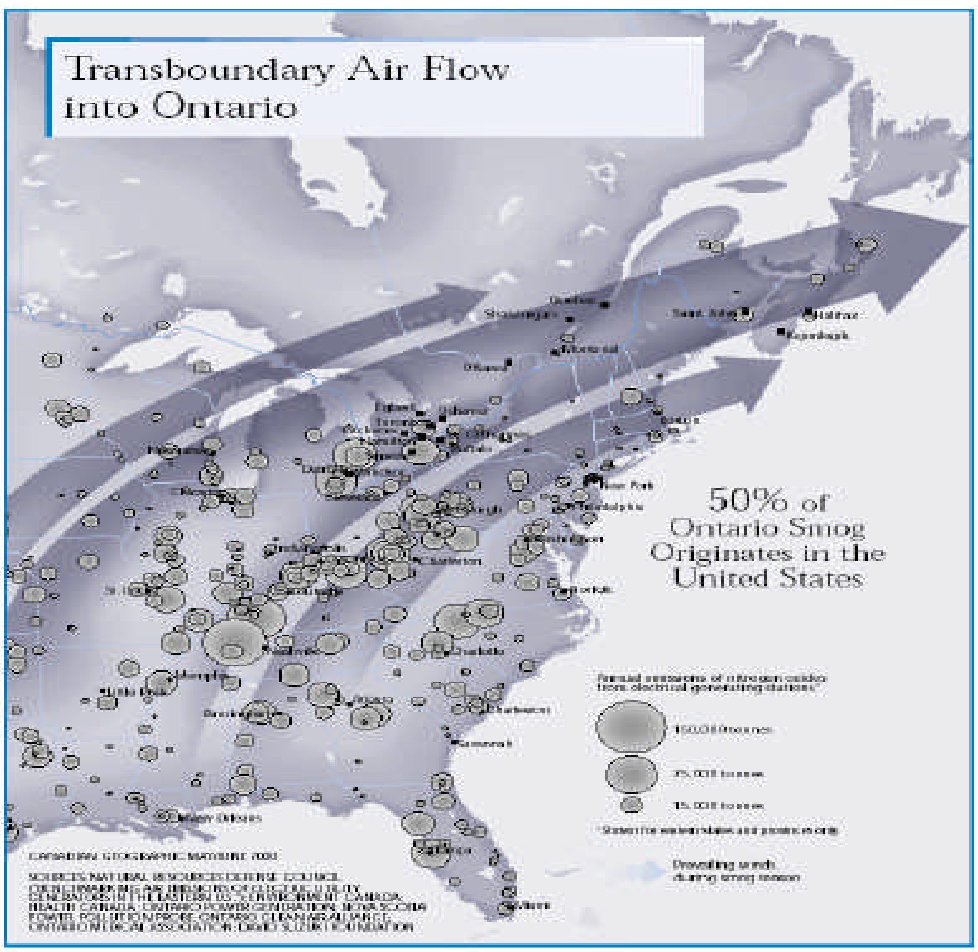
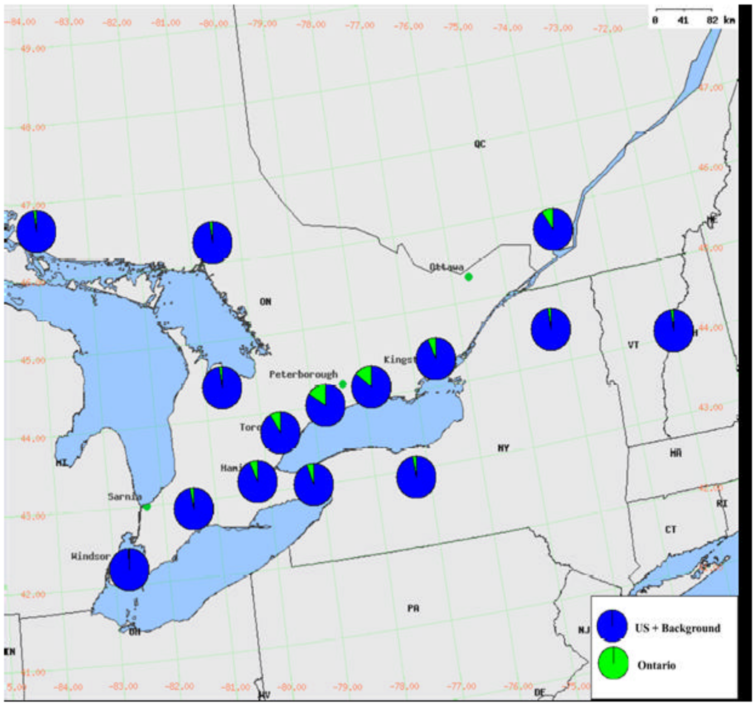


Figure A-4: Sulphur dioxide emissions from power plants shown as dots that vary in size according to their emission inventories
U.S. 1995 (with 2001 updates) and Canada 1999 Emission Inventories
(source: Ontario Ministry of the Environment)



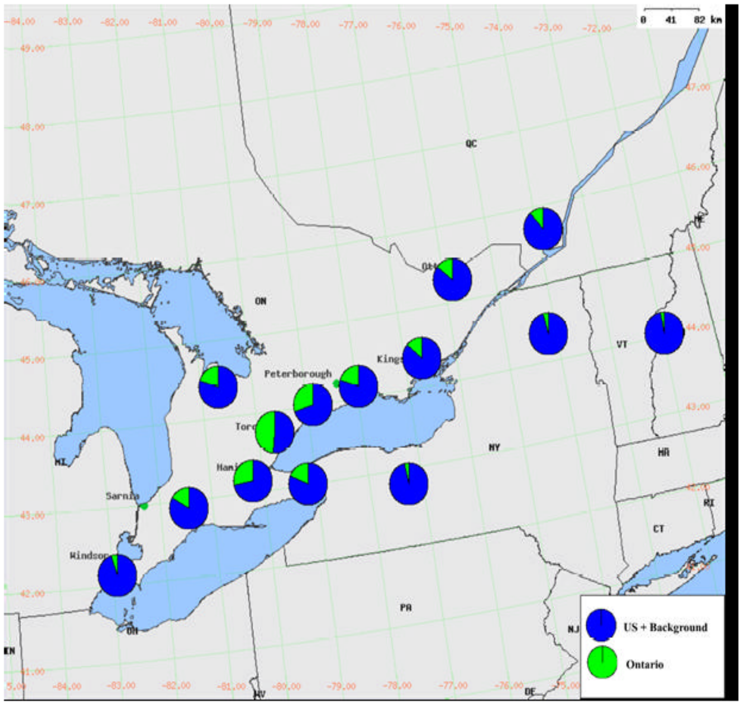
TRANSBOUNDARY EMISSIONS vs ONTARIO CONTRIBUTIONS

● ONTARIO SOURCES ● US CONTRIBUTION



OZONE

Figure 3.4: Graphic of Transboundary vs. Ontario Contribution for Ozone on High Concentration Days during 1998 Spring/Summer Season.



PM 2.5

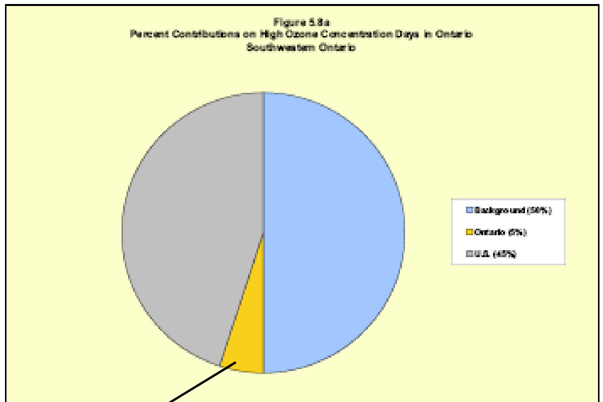
(Air Quality in Ontario, 2005 - Ontario Ministry of the Environment)

Figure 3.5: Graphic of Transboundary vs. Ontario Contribution for $PM_{2.5}$ on High Concentration Days during 1998 Spring/Summer Season.

(source: Ontario Ministry of the Environment)

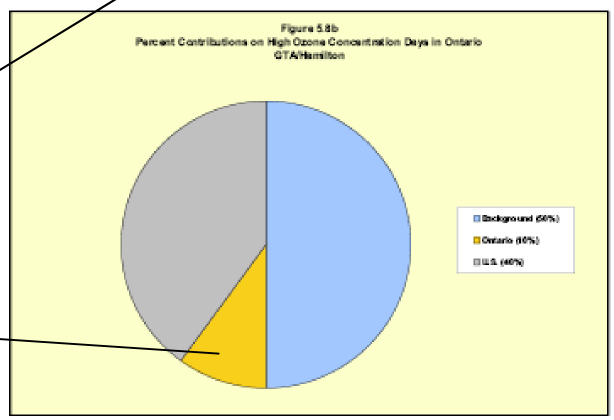
PM 2.5 originates from particles emitted directly from sources and from particles formed in the atmosphere. The precursor gases SO2, NOx, ammonia and certain VOCs react in the atmosphere to form ammonium sulphates, ammonium nitrate and organic particles. Air quality models include all of these components.

% CONTRIBUTION ON HIGH OZONE DAYS IN ONTARIO



Southwestern Ontario

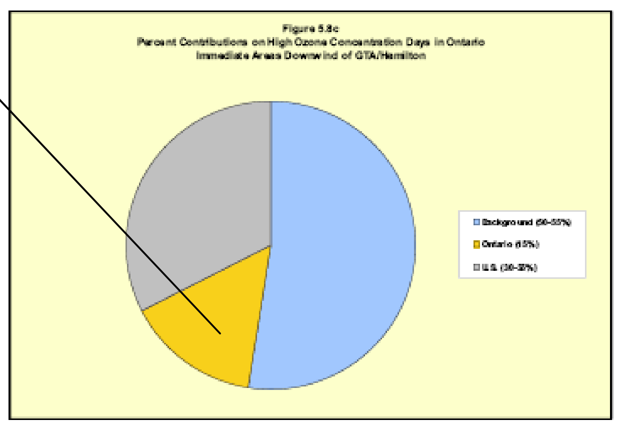
* **Background - 50%**
US Sources - 45%
All Ontario Sources – 5%



Coal emissions represent a small portion of this amount

GTA/Hamilton

* **Background - 50%**
US Sources - 40%
All Ontario Sources – 10%



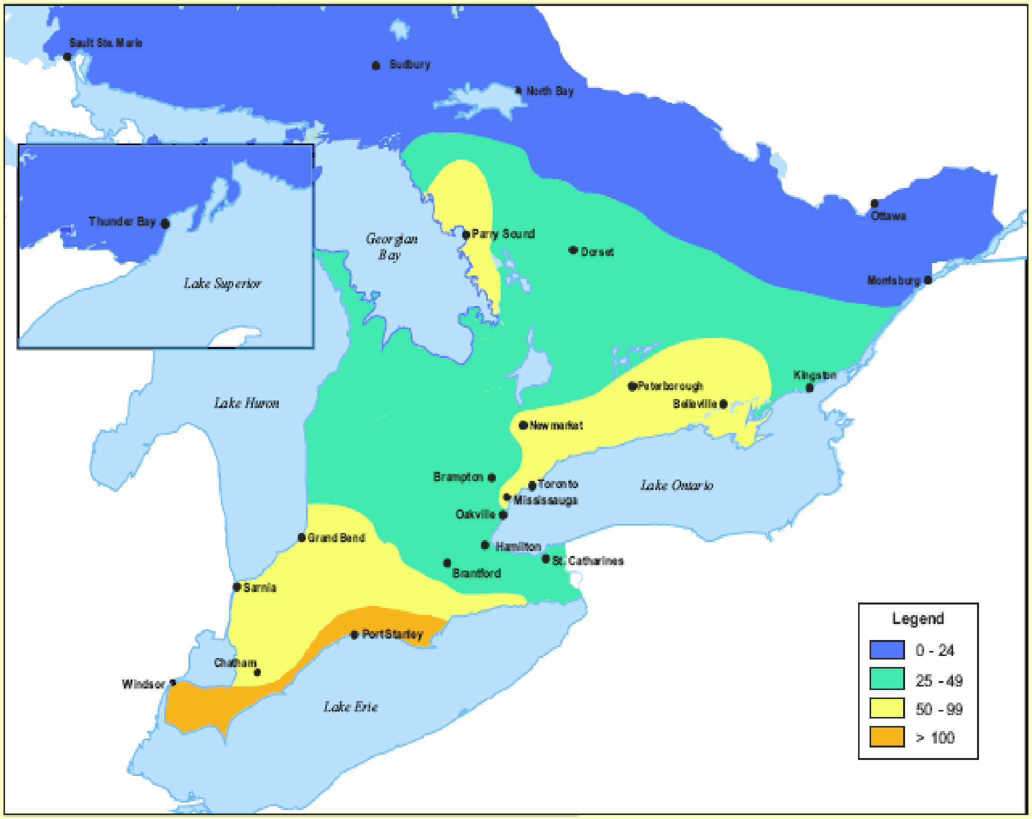
Downwind of the GTA/Hamilton

* **Background - 50%-55%**
US Sources - 30-35%
All Ontario Sources – 15%

*Background ozone concentrations refer to the contributions at a given location in Ontario that are primarily the result of manmade and natural emissions from outside North America and natural sources within North America.
(Air Quality in Ontario, 2005 - Ontario Ministry of the Environment)

On days of <u>low ozone</u>, background ozone concentrations are expected to dominate, and **manmade sources would not contribute as much**. Background contributions were estimated to be about 75-80% for the GTA/Hamilton and 80-85% downwind of GTA/Hamilton. (Ministry of the Environment)

Figure 2.5
Geographical Distribution of Number of One-Hour Ozone Exceedances Across Ontario
(2005)



Higher ozone excedences were recorded on the northern shores of Lakes Erie and Ontario and the southeastern shores of Lake Huron and Georgian Bay. This is attributed to the long range transport of pollutants from the U.S. ("Transboundary Air Pollution in Ontario", Ministry of the Environment)

"The increases in summer and winter ozone means appear to be largely related to rising global background ozone concentrations throughout Ontario. … Potential contributions to the increases in the summer composite means may be related to meteorological factors and long range transport of ozone and its precursors from the U.S." (Air Quality in Ontario, 2005)

♦ The government report, prepared to justify the coal closure mandate, did not include either the Thunder Bay or Atikokan coal facilities in their environmental assessment, indicating that they "emit a small fraction of the total provincial coal fired generation emissions (i.e. <5%) and are outside the main airshed in which southern Ontario coal fired generation emissions interact". (Ontario's Cost-Benefit Analysis - Replacing Ontario's Coal-Fired Electricity Generation, prepared for the Ontario Ministry of Energy, April, 2005)

♦ Of the 38 Air Quality monitoring sites in Ontario, Thunder Bay was the only site that did not record any hours of ozone above the one hour ambient air quality criteria. The designated Canada wide Standard reporting sites were all above the 2010 CWS … for ozone in 2005 with the exception of Thunder Bay …" (Ministry of the Environment, Air Quality in Ontario, 2005)

♦ As part of the government initiatives to lessen the impact of air contaminants, “The province has in place a regulation (O. Reg. 397/01) that establishes annual caps with respect to NO_x and SO_2 emissions from Ontario Power Generation’s (OPG) fossil fuel power plants and the electricity sector.” (Ministry of the Environment) OPG fossil fuel facilities meet these established criteria.

♦ Air quality monitoring equipment was dismantled in Atitkokan because there was nothing of significance worth monitoring.

Net Impact of Coal-Fired Power Plants on Ontario’s Air Quality

♦ Small (less than 7% overall); negligible from Thunder Bay and Atikokan sites

♦ An assessment of contribution of harmful emissions to air quality from Ontario's coal fired power plants was completed as part of the government's Cost-Benefit Analysis. This report demonstrates that coal fired power in Ontario contributes **less than 1% to ozone in southern Ontario; less than 5% to PM_{10}** ("Primary PM_{10}, particulate nitrate, and particulate sulphate concentrations were summed to arrive at total PM_{10} concentrations." (Ontario’s Cost-Benefit Analysis - Replacing Ontario’s Coal-Fired Electricity Generation, prepared for the Ontario Ministry of Energy, April, 2005)

♦ The role of Ontario’s power plants in forming ground-level ozone in Ontario was studied in a report by RWDI consultants, 2004. The results indicated that had the power plants been removed, there would have been almost no difference. “The reduction in ozone formation across the region would have been imperceptibly small.” (Pain Without Gain, Fraser Institute, January, 2005)

♦ “Overall, closing down the CFG (coal fired generating) facilities is forecast to improve air quality in most parts of southern Ontario. … However, these improvements are small compared to the overall ambient concentrations of these pollutants. The ambient concentrations of these pollutants are influenced by various sources including transboundary air pollution and vehicle emissions.” (Ontario’s Cost-Benefit Analysis - Replacing Ontario’s Coal-Fired Electricity Generation, prepared for the Ministry of Energy, April, 2005)

Affects of Coal-Fired Power Generation on Health and the Environment

The "purpose" for this proposed Regulation includes the statement that, “These emissions are associated with major health impacts (e.g., premature death, increased hospital emissions for patients with asthma and chronic lung disease) as well as environmental impacts (e.g., buildings, crops and ecosystems).”

While “these emissions” may be associated with health and environmental impacts, the degree to which coal fired generation contributes, is very minimal. The wording here is designed to mislead, to insinuate that coal fired generation is a significant cause and contributor to these concerns.

Note the following:

♦ The Ministry of the Environment operates an extensive network of air quality monitoring sites - 38 locations - across the province. An AQI (Air Quality Index) is based on recordings from these sites, of pollutants that have adverse effects on human health and the environment.

♦ The data collected is summarized and included in the Ministry's Air Quality report. The most recent is the data from 2005. Most sites showed good or very good air quality 85% of the time; moderate 13%-15%; poor on average, less than 1.5% of the time. (. In spite of the fact that the summer of 2005 was particularly hot and smoggy. Due to decreased availability of hydroelectric power and increased air conditioning use, coal fired power was required more frequently. Lakeview GS was in service for the first quarter of that year.)

♦ The following chart shows the impact of emissions on health and the environment. This chart is from the 2005 Air Quality report. We have included coal fired contribution at the bottom.

Table 5.1: Air Quality Index Pollutants and Their Impacts*

Index	Category	Ozone (O_3)	Fine Particulate Matter ($PM_{2.5}$)	Nitrogen Dioxide (NO_2)	Carbon Monoxide (CO)	Sulphur Dioxide (SO_2)	Total Reduced Sulphur (TRS) Compounds
0-15	Very good	No health effects are expected in healthy people	Sensitive populations may want to exercise caution	No health effects are expected in healthy people	No health effects are expected in healthy people	No health effects are expected in healthy people	No health effects are expected in healthy people
16-31	Good	No health effects are expected in healthy people	Sensitive populations may want to exercise caution	Slight odour	No health effects are expected in healthy people	Damages some vegetation in combination with ozone	Slight odour
32-49	Moderate	Respiratory irritation in sensitive people during vigorous exercise; people with heart/lung disorders at some risk; damages very sensitive plants	People with respiratory disease at some risk	Odour	Blood chemistry changes, but no noticeable impairment	Damages some vegetation	Odour
50-99	Poor	Sensitive people may experience irritation when breathing and possible lung damage when physically active; people with heart/lung disorders at greater risk; damages some plants	People with respiratory disease should limit prolonged exertion; general population at some risk	Air smells and looks brown; some increase in bronchial reactivity in asthmatics	Increased symptoms in smokers with heart disease	Odour; increasing vegetation damage	Strong odour

Coal contribution ^ ^ ^ ^ ^

VOCs 0.125% 1.438% 13% 0.49% 24%

\+ NOx 13%

♦ There were no impacts for healthy people 85% of the time. For 15% of the time, odour and **potential** "respiratory irritation" in **sensitive people during vigorous exercise;** those with heart/lung disorders potentially at some risk. (Noted elsewhere, "moderate" air quality days, according to the Ministry of the Environment, "may have some adverse effects for very sensitive people".)

♦ Environmental impacts include a "potential damage to very sensitive plants; damages some vegetation". Again, however, this is a result of all contributors of NO_x and SO_2, of which coal fired generation is only a smaller portion.

♦ Asthma is most commonly triggered by pollens, dust, pet dander, mould, stress, as well as outdoor air pollution; respiratory viral infection is one of the most common causes. (Canadian Lung Association) Indoor air pollution is 2-5 times higher, occasionally 100 times higher, than outdoor levels. On average, we spend more than 90% of our days indoors. Coal fired generation therefore contributes an insignificant amount to hospital admissions related to asthma.

Greenhouse Gas Emissions

♦ Reducing CO_2 will not improve smog in our province. CO_2 is not a pollutant or a toxic. (It is an essential component of sustaining life on earth.)

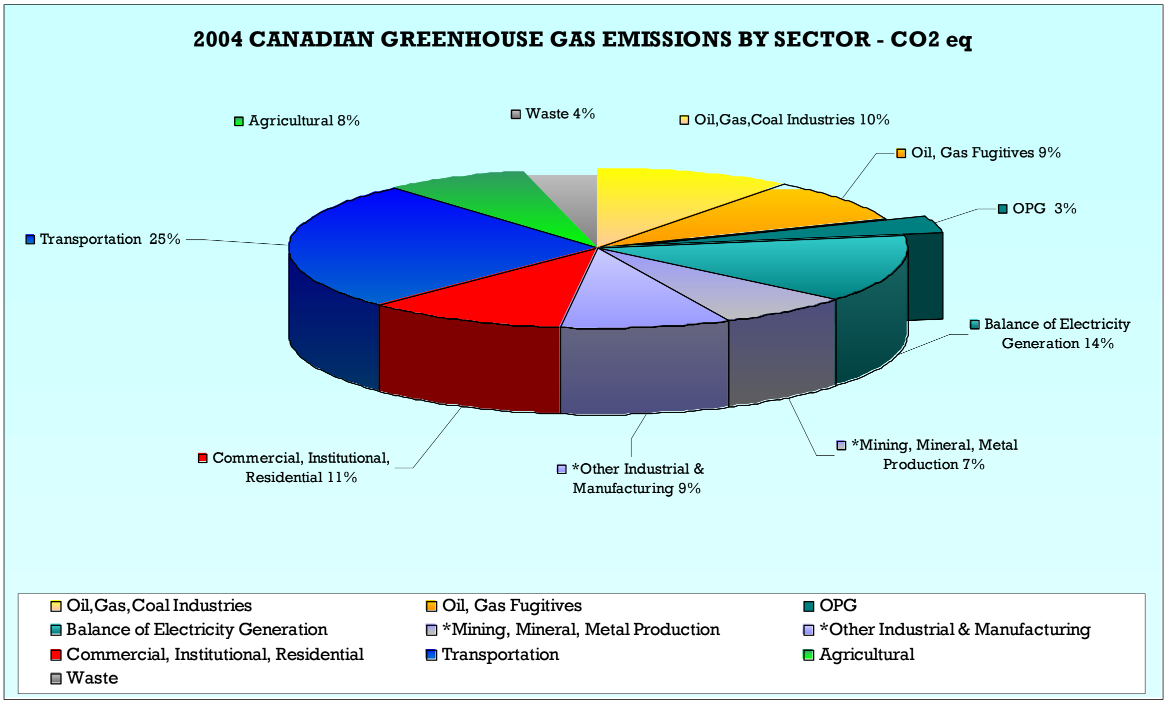
♦ Human contributions represent less than 4% of all greenhouse gas releases. This amount however is increasing and causing concerns regarding climate change potential.
Canadian emissions account for about 1.8% of this 4%, or 0.072% of these global man made emissions. ((Natural Resources Canada - Global Emission Outlook)

♦ According to Environment Canada statistics for 2004, OPG coal plants contribute about 3% to the national total; 0.054% globally (manmade emissions); 13% to Ontario greenhouse gas emissions.
(see Charts, following)

♦ Emissions impacting climate change will not be reduced significantly with the closure of Ontario's coal-fired power plants. Replacement generation is slated to come from natural gas-fired power. Although natural gas emits about 55% the CO_2 of coal generation at point of combustion, there are significant emissions associated with production, flaring, processing and transport of natural gas. There is marginal net benefit of using natural gas in place of coal.
(For comparison, and statistics, see section (iii), Net Impact of Transitioning to an Alternative Fossil Fuel")

Conclusion

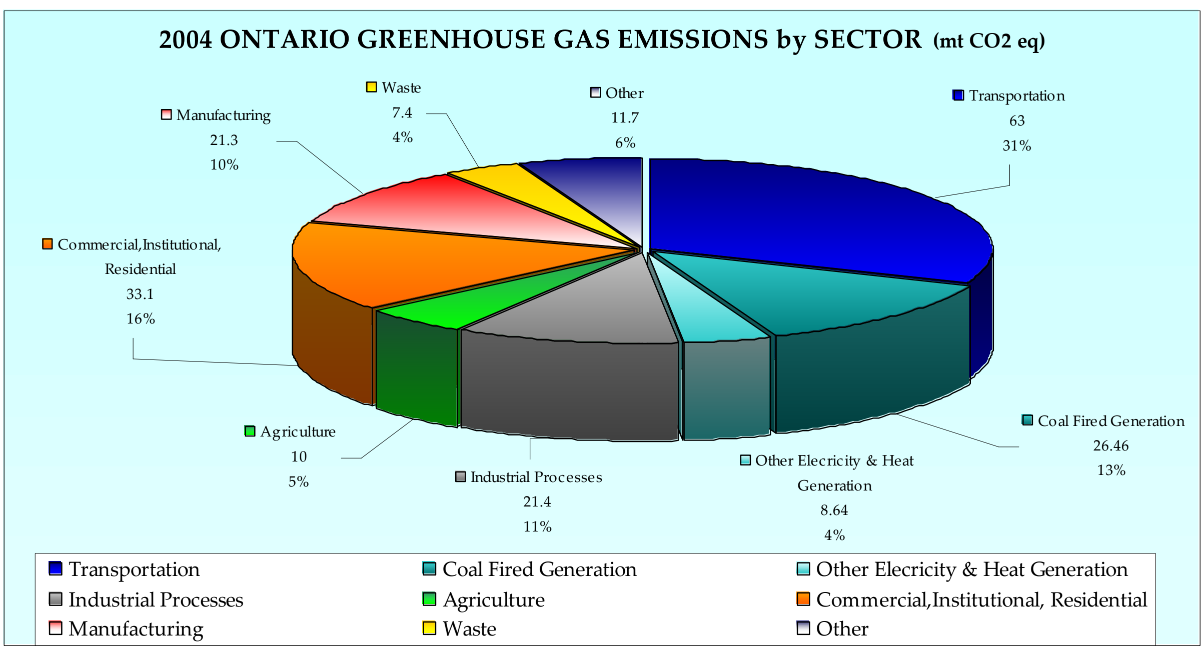
The coal fired power plants are large facilities, single source emitters of pollutants of some concern. However, they do not constitute a major portion of air quality concerns in Ontario.



"Environment Canada, Summary of Canada's 2004 Greenhouse Gas Inventory"
*Includes both combustion emissions and process emissions

- ♦ Total Canadian Greenhouse Gases 758.0 MT
- ♦ OPG (coal) Greenhouse Gas Emissions 26.5 MT
- ♦ % OPG (coal) of all Canadian GHG emissions approx. 3%

(includes Lakeview Generating Station, since removed from service)



Environment Canada, National Inventory Report, 1990-2004 – Greenhouse Gas Sources and Sinks in Canada – Annex 12: Provincial/Territorial Greenhouse Gas Emission Tables, 1990-2004" and Ontario Power Generation, 2005 Sustainability Development Report, Appendix B, www.opg.com

(ii) Emissions Can be Economically and Successfully Reduced

The pollutants of greatest concern in relation to coal fired power generation, are the emissions that can be most affordably and successfully reduced. This success is evidenced in reports generated by and for the Ministry of Energy, including the Cost Benefit Analysis Report and the OPA's IPSP Discussion Paper Emission Control Alternatives for Ontario Coal Generators, 1 April 2007. These reports show that the emissions from Lambton Generating Station Units 3 and 4 are approximately 75%-85% less for NO_x and SO_2; 95% less for mercury emissions, as a result of emissions abatement technology installed on these units. Subsequently, they are ranked 4th and 9th cleanest of the 500 coal fired plants in North America. Greater reductions can be obtained, as noted below.

♦ "Proven and cost-effective emission control technologies are available that can be added to existing coal stations to achieve significant reductions. Selective Catalytic Reduction (SCR) can reduce NOx emissions by up to 80%, while de-sulphurization scrubbers can reduce SO_2 emissions by 90+ percent. …" (Ontario Ministry of the Environment, "Coal-Fired Electricity Generation in Ontario")

♦ The Ministry encourages other industries to employ the same emissions reduction technology that is readily available for coal powered plants, to reduce industrial emissions. The Ministry recognizes the benefit of NO_X abatement technology reduces emissions by "80-95%", and technology for SO_2 reduction including Dry Flue Gas De-Desulphurization reduce emissions "55-95%", as well as Wet Flue Gas Desulphurization systems which reduce emissions "90-98%". ("Appendix II - Ontario's Industry Emissions Reduction Plan: Proposal for a Nitrogen Oxides (NO_X) and Sulphur Dioxide (SO2) Regulation", June, 2004)

♦ The Ministry has joined with other agencies to encourage the adoption of technologies that would reduce emissions from U.S. coal fired power plants by up to 90% into the regional air shed.

♦ "... if currently existing remediation technology were used, the air quality effects from coal fired power plants are comparable to those from natural gas plants and neither could be distinguished from the regional background at distances more than a few km from the source."
("A Regional Modeling Study of the Effects on Air Quality of Electric Power Generation by Fossil Fuels" Waterloo Centre for Atmospheric Sciences, May 26, 2006)

♦ This study, funded in part by the Ontario Ministry of the Environment, reports that "currently existing remediation technology on the coal plant reduces both the SO_2 and NO_X contributions to about 0.3% when averaged across southern Ontario and about 1% within 20 km of the largest plant".

♦ Electrostatic precipitators (dry ESP) installed at coal fired power plants, including Lambton Generating Station, reduce approximately 99% of particulate matter. A wet ESP would remove over 95% of the remaining 1%. (This represents superior reduction of PM than natural gas use.)

With regard to mercury and other toxic pollutants:

♦ The US Department of Energy indicates that mercury can be reduced 80%-90%+ using combined scrubber/SCR technology.

♦ "Essentially all coal-fired power boilers in Germany are equipped with both SCR systems and limestone based wet scrubbers. Total mercury capture in these systems exceeds 80% system-wide."

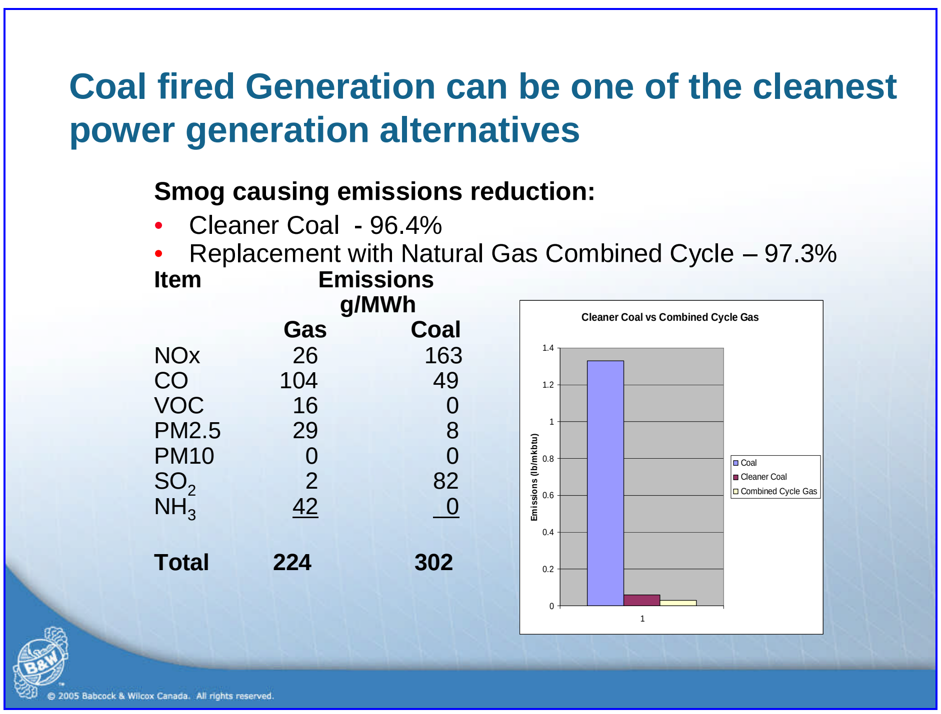
("How Low Can We Go?" Babcock & Wilcox) Germany uses coal fired generation for 50% of its power needs.

♦ According to Environment Canada, "capture of mercury from ... coal-fired power plants ... on the order of 60-90% is achievable. ..." This report lists both current and emerging technologies, with removal rates for each, affirming the conclusion that mercury emissions reductions of 60-90% are achievable by 2010. (Submission filed by Environment Canada to U.S. EPA, March 30, 2004)

♦ Nanticoke Generating Station "is achieving more than 60% capture of mercury in coal burned through existing pollution control equipment and fuel blending". Nanticoke has not yet been outfitted with scrubbers, as has Lambton Generating Station. (Presentation by the Ministry of the Environment to the Great Lakes Bi-national Toxics Strategy Mercury Work Group on May 17, 2005)

♦ Mercury removal of at least 90% can be achieved by methods developed by Babcock, Wilcox which involves low cost and collection of mercury that ensures that it will not be re-emitted to the environment. ("How Low Can We Go?") Other mercury emissions reduction technologies (Eco System – Power Span Corp.) are in process, or development.

♦ Example:



Many people are unaware that current technology can be applied to existing coal power plants to make them very nearly as clean as modern, efficient Natural gas turbine combined cycle power plants. Application of these technologies in Ontario would reduce smog and acid rain causing emissions by more than 96%. BABCOCK & WILCOX (with permission)

♦ See Charts, page 11, comparing air contaminant emissions with and without reduction technology

(iii) Net Environmental Impact of Transitioning to an Alternative Fossil Fuel

The proposed coal closure cannot be viewed in isolation of the replacement generation for these resources. The Ontario Power Authority, at the direction of the Ministry of Energy, is in process of procuring 7,000 MW of natural gas fired generation (in addition to the existing 5,000 MW of gas fired power) as replacement for coal fired facilities. Natural gas generation produces emissions, including greenhouse gas emissions that must be taken into consideration when assessing the **net benefit** of ceasing to utilize coal for electricity generation.

♦ As noted in the previous section, air contaminant emissions of concern from coal fired power plants can be reduced to a level comparable with natural gas.

♦ Natural gas "production has significant environmental consequences in the form of wilderness and habitat destruction…. Contrary to its clean image, natural gas contributes to climate change. Although burning natural gas produces fewer greenhouse gas emissions than coal or oil (25–40% lower, per unit of generated electricity), natural gas still creates emissions when it is produced, processed, and transported…" (Suzuki Foundation submission to the Ontario Power Authority, Fall, 2005)

♦ Regarding greenhouse gas emissions, note:

(a) Natural gas emits about 55% - 63% the CO_2 of coal generation at point of combustion. (63.06% the CO2 of coal at point of combustion. - Carbon Dioxide Emissions from the Generation of Electric Power in the United States, July 2000, staff of the U.S. Department of Energy and the U.S. Environmental Protection Agency; Natural Resources Canada, 56.67%).

However, there are significant emissions associated with production, flaring, processing and transport of natural gas.

(b) "Burning gas instead of coal also sounds good and green since it cuts CO_2 emissions in half. In practice it may be the most dangerous energy source of all, because natural gas is 23 times as potent a greenhouse gas as CO_2. … even a 2 percent leak of the natural gas from the production sites to the power stations makes it as bad as burning coal. In practice, the leak rate is 4 percent, so it may be more than twice as bad as burning coal or oil."
(Mr. James Lovelock - address to the Canadian Nuclear Association Annual Seminar, March 10, 2005)

(c) "the contribution of natural gas generation to climate change is only slightly less than coal (on an energy basis). ... Even using the best-case scenario shows that natural gas is a deficient strategy to address climate change." (David Suzuki Foundation – Submission to the Ontario Power Authority, fall, 2005)

(d) Natural gas GHG emissions are about 25% less than coal, on a lifecycle basis. (IAEA Spadaro et al. 2000). This gap could be closed by burning biomass with coal.

(e) TransCanada Pipelines Ltd. reported more than twice the emissions at the Kenora Compressor Station from the compression/recompression of natural gas coming into the Province, than from Atikokan and Thunder Bay coal fired stations combined.

(f) "If life cycle analysis was used and other greenhouse gases were taken into account, electricity generation from fuels other than coal would show similar or even higher GHG emissions …" (World Energy Council)

(g) "In Canada … natural gas is a larger source of carbon dioxide emissions than coal. Natural gas 29.0%; Coal 19.2% (Carbon Dioxide Fact Sheet, 2004)

(h) Considering the significant amount of new gas fired generation proposed for Ontario, and the future supply concerns, "…liquefied Natural Gas (LNG) is expected to play a critical role in addressing the forecast supply gap." (Navigant Consulting Report to OPA) There are greenhouse gas implications of using LNG. LNG entails an energy loss of 15% - 30% in the transport, liquefaction and regasification processes.

(i) Greenhouse gas emissions have increased in Canada from 1990 to 2003. …42% of the increase is as a result of "fugitive releases (e.g. methane leaks from pipelines)... most of this increase is the result of greater traffic through energy pipelines..." (Environment Canada – Summary of Canada's Greenhouse Gas Inventory)

(j) CO_2 emissions from coal plants can be reduced by:

Co-firing with biomass, as is successfully done in Europe and in preliminary stages at Nanticoke – resulting in up to 30% reduction in CO_2 ;

Implementing emissions control technology and other equipment upgrades to increase unit efficiency;

Re-establishing emissions trading (A practice of OPG prior to coal closure mandate) ;

Using fly ash from coal combustion in cement production. Each tonne of ash used in place of shale avoids a tonne of carbon dioxide being released into the atmosphere. Nanticoke diverts 300,000 – 400,000 tons of fly ash from land fill to cement companies, offsetting one ton of CO_2 for each ton of fly ash used;

Carbon capture and sequestration, a process that, although still in the developmental stage, is progressing rapidly for market use.

CONCLUSION

Coal fired power generation does not produce a "major" portion of Ontario's air contaminant emissions. The emissions impact from Atikokan and Thunder Bay Generating Stations are minute. Therefore, the health and environmental benefits have been greatly exaggerated. The emissions that do pose concerns can be readily, affordably, and successfully reduced to near par with natural gas fired generation. Switching to natural gas fired generation will not lessen global greenhouse gas emissions from power generation in Ontario.

Replacement generation will come at great cost to the Ontario economy, and to the average ratepayer, at very minimal environmental benefit.

♦ At point of combustion, natural gas produces 35%-45% less greenhouse gas emissions. However, when lifecycle emissions of natural gas for production, refining and transport are considered, natural gas has little benefit and may actually be worse for the environment in terms of climate change. As noted, the Kenora Natural Gas Compression Station alone reported higher GHG than Atikokan and Thunder Bay coal-fired stations, combined.

♦ Methane (primary constituent of natural gas) is 23 times more potent a greenhouse gas than CO_2.

The cost impacts of the coal closure are huge, and will most definitely impact provincial GDP more than 1%.

♦ Significantly more natural gas-fired generation in the GTA and "Golden Horseshoe" will create higher rates of ozone and particulate matter, increasing the health impacts in urban areas. (OPA) With shorter emissions stacks and higher concentrations of smog producing pollutants where pre-ambient conditions for ozone and smog occur, natural gas fired generation may be worse for the environment than the current coal fired generation plants.

♦ The OPA suggests that gas fired power plants may utilize the option for oil fuelled power generation. "to ensure operational capability during winter peak periods when gas demand and electricity demand peak simultaneously." The environmental impacts are greater from oil, than coal-fired generation.

♦ Single cycle natural gas power plants are proposed for peaking periods. The higher emissions associated with these facilities have not been compared to coal-fired generation, for either greenhouse gas, or air contaminant emissions.

♦ The uncertainties and tight resource balance anticipated from 2010 to 2020 will likely force imports of power from coal-fired power plants less environmentally "clean" than existing Ontario coal-fired plants (which are in the top 10% in North America).

♦ If system reliability is compromised, power interruptions may occur, thereby impacting the environment as a result of industrial and manufacturing power losses. For example, NOVA Chemicals reported that unexpected power outages introduce problems, including safety and environmental incidents typically associated with crash shutdowns and start-ups. (Letter to Minister of Economic Development and Trade, April 8, 2005)

♦ The coal closure regulation will increase electricity costs an anticipated 70%. This will cause significant damage to the Ontario economy. The results and implications are manifold, with far reaching impacts to the health and welfare of Ontarians.

♦ Higher energy costs cause disproportionate harm to those least able to cope - the elderly, the infirm, those on fixed and lower incomes. This will translate into issues such as lack of ability to afford air conditioning, or using wood burning for residential heat.

♦ It is reported that many newly constructed homes have installed natural (wood) burning fireplaces, rather than natural gas, due to the rising cost of gas. This impacts the environment, as there is more particulate matter (PM) emitted from residential wood combustion (wood stoves and fireplaces) in Ontario, than from all the provincial coal fired power plants combined. (Environment Canada – Criteria Air Contaminants Emission Summaries)

♦ Less funding will be available to address emissions from sectors of greater environmental impact than coal fired generation. (Transportation is one of the largest sources of Canadian carbon dioxide emissions. Roughly half of the carbon dioxide emissions from the transportation sector are created by the cars and light trucks we drive for personal use. The rise in transportation emissions is attributed to growth in use of SUVs and minivans, which almost doubled between 1990 and 2003.)