


ONTARIO POWER AUTHORITY

November 9, 2006


Ontario's Integrated Power System Plan

Discussion Paper 4: Supply Resources

Ontario Power Authority

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November 9, 2006

To Ontario's Electricity Consumers and Stakeholders:

Today, I am pleased to deliver for your consideration "Discussion Paper #4: Supply Resources," the Ontario Power Authority's (OPA's) fourth of eight papers on the Integrated Power System Plan (IPSP).

Building on OPA's "Scope and Overview" paper (#1), released in June, this series of papers is intended to focus on specific aspects of planning. Together, the papers will provide our current assessment of the building blocks for the IPSP, and the feedback they generate will be important guidance for their further development and the eventual preparation of the plan. Please see the table on the next page outlining the list of IPSP papers.

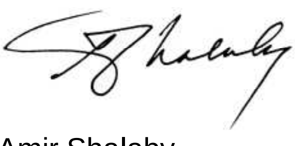
The purpose of the Supply Resources paper is to elicit discussion on the paths Ontarians collectively need to take to ensure the highest success in meeting Ontario's needs for a secure and adequate supply of electricity. Concerted effort is required and early focus on planning will be essential.

For details on stakeholder input and participation opportunities (and other IPSP matters), please see the OPA's dedicated IPSP web page (www.powerauthority.on.ca/IPSP/).

In the months ahead, I look forward to receiving your advice, thoughts and comments through the IPSP consultation process and to sharing with you the additional planning documents as they are developed. In addition to the comprehensive report we are releasing today, OPA is releasing papers 5, 6 and 7 over the next few days in support of certain aspects of the other components of the plan.

I strongly believe that developing a shared understanding of the planning challenges and the concrete steps needed to address them will focus the discussions, improve the dialogue, and ultimately result in a better plan for the benefit of all Ontarians.

Yours sincerely,



Amir Shalaby
Vice-President, Power System Planning

OPA's IPSP Discussion Papers

#	Discussion Paper Title	Release
1	Scope and Overview	June 29
2	Load Forecast	Sept. 07
3	Conservation and Demand Management	Sept. 22
4	**Supply Resources**	**Nov. 9**
5	Transmission	Nov. 13
6	Sustainability	Nov. 10
7	Integrating the Elements - A Preliminary Plan	Nov. 14
8	Options for Procurement	TBD

NB: For details on stakeholder input and participation opportunities (and other IPSP matters), please see www.powerauthority.on.ca/IPSP/, the OPA's dedicated IPSP web page.

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Summary

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. But with Ontario's population continuing to grow along with the importance of electricity in our daily lives, the demand for electrical power in Ontario is moving steadily upward, even with our best efforts at conservation and energy efficiency. At the same time, many of our workhorse baseload nuclear generating units are coming to the end of their service lives, while concerns for the environment are prompting a shift away from fossil fuels such as coal, which will eventually be phased out.

The challenge we face is both critical and exciting – critical because 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. 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.

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. This paper is the fourth in a series of discussion papers issued by the OPA to provide background information and encourage stakeholders to contribute in the development of the Integrated Power System Plan (IPSP), our action plan to assure the province's reliable and sustainable electricity future to 2027.

With this paper, our focus is on the generation supply resources available to Ontario for meeting our short- and long-term electricity requirements. This paper:

- identifies potential short- and long-term generation resources
- describes the operating characteristics of each generation type, defines the balance between baseload and peak-load supply, and clarifies the role that a "smart gas strategy" will play
- reviews environmental and other implications of each resource category.

Resources identified have been screened for technical and commercial viability, as well as for reliability, cost-effectiveness, flexibility and robustness, environmental performance and social acceptability. The sustainability framework leading to these criteria is explained in the Sustainability paper (discussion paper #6).

The Integration paper (discussion paper #7) will report the results of "integrating" the candidate generation with conservation and demand management (CDM) and transmission investments. We will then test the preliminary plan against the same sustainability criteria to further refine and improve it, taking into account your comments and advice.

Ontario's existing installed generation capacity relies heavily on hydroelectric generation (7,768 MW (megawatts)), nuclear energy (11,414 MW) and coal (6,434 MW). Natural gas and oil provide another 5,103 MW, followed by wind at 305 MW and biomass at 70 MW.

Here is a brief overview of the proposed IPSP generation "building blocks" for the future. You will find a complete summary of these resources in Tables 2.5 and 2.6 of this document. (Just under half of the resources identified as being "near-term potential" are committed under procurement or are under development.)

Hydroelectric:

- *Near-Term Potential* - Between now and the end of 2015, we expect that approximately 700 MW of additional capacity will come online with a corresponding median energy contribution of 3,500 GWh (gigawatt hours) per year. Projects involving rehabilitation and efficiency upgrades have achievable unit energy costs in the 3-7 cents per kWh range.
- *Future Potential* - Hydroelectric potential at undeveloped ("greenfield") sites comprises 2,200 MW of additional capacity with a corresponding energy production of approximately 7,000 GWh per year. Most of the sites are located in remote areas of northern Ontario and will require transmission infrastructure upgrades. We project the full development of these resources to be feasible in the 2016-2025 timeframe. Unit energy costs for new hydroelectric plants in northern Ontario appear to be in the 8-10 cents per kWh range. In some cases, these could be somewhat higher.
- *Other* - There is about 1,100 MW of hydroelectric potential considered constrained from future development because the sites are within provincial parks or on restricted lands.

Wind Power: Wind power has an estimated capacity potential of 8,700 MW. Unit energy costs, at the site, range from 8.5 cents/kWh to 10 cents/kWh. Preliminary studies suggest that wind would be available, on average, 17 percent of the time in summer and 41 percent of the time in winter, and that the variability of wind generation can be managed effectively at a penetration level of 5,000 MW in Ontario.

Wind power development at southern Ontario sites appears to be more cost-effective than in northern Ontario, after consideration of the need for transmission lines and re-inforcements.

Bioenergy: A total potential of 1,250 MW is identified for the period to 2027. About 300 MW could be possible by the end of 2015. For the most part, bioenergy resources are small (typically less than 10 MW capacity) and at a single site, and thus open to development under Standard Offer Programs (SOP). The bioenergy resources surveyed in this paper include:

- *forestry biomass (harvest and mill residues, woody plantations)*
- *agricultural biomass/biogas (crop and animal residues, dedicated crops)*
- *municipal solid waste* (MSW)
- *municipal wastewater treatment biogas (digester gas).*

Nuclear: Ontario's nuclear units will reach their end of life between 2013 and 2022. The June 13, 2006, ministerial directive asks the OPA to plan for nuclear capacity to meet baseload electricity requirements, limiting the installed in-service capacity over the life of the plan to 14,000 MW.

Nuclear generation is recognized as necessary to fill Ontario's large requirement for baseload energy. It is also seen as a power source that does not emit greenhouse gases, is potentially cost-effective and has significant local support. Refurbishment would not require additional land. (While refurbishment decisions rest with facility operators and owners, for planning purposes, we have assumed that refurbishment will go ahead.) We support the continuation of preparations for the refurbishment of the Pickering B nuclear units.

Options to develop new nuclear units are also being considered for existing licensed nuclear sites. Bruce Power and Ontario Power Generation have applied for site preparation licenses for new nuclear plants at the Bruce and Darlington sites respectively.

The lead times associated with Environmental Assessment (EA) process and approvals, combined with construction and commissioning of a new nuclear unit, can range from nine to 12 years. Given the long lead times, we believe these activities should be pursued in order to keep this option viable.

Natural Gas: We intend to pursue a "smart gas strategy" where natural gas is a supplemental resource, with nuclear providing baseload power and increasing amounts of renewable resources beginning to contribute to grid-based energy. Natural gas provides an effective balancing role to address the intermittent nature and low availability of renewable supplies.

Coal: We have conducted assessments to:

- plan for the replacement of coal-fired generation by cleaner sources in the earliest practical timeframe
- ensure adequate capacity and electric system reliability
- manage key risks and uncertainties during the transition period.

The results of these assessments are discussed in the Integration paper (discussion paper #7).

Storage: The potential system benefits of storage in Ontario have been considered. Storage can be provided in several ways including: (i) pumped generation storage, (ii) storage at a neighbouring utilities' system and (iii) new emerging storage technologies such as superconducting magnetic energy storage (SMES), flow batteries or compressed air energy storage.

Promising New Technologies: A number of technologies have the potential to play an important role in the improvement of Ontario's electricity infrastructure. These will be enabled through Standard Offer Programs. We propose to include up to 1,000 MW of installed capacity in the IPSP. The new technologies include distributed resources (solar photovoltaic (PV), fuel cells, micro-turbines and micro-wind at customer sites, cogeneration and micro-CHP and residential Stirling engines) and gasification.

While these technologies can be considered promising, practical and commercial feasibility needs to be established. We will maintain a monitoring role and include updates in future IPSPs.

Imports: Short-term imports are not formally considered in developing the plan, but their potential availability is considered in assessing overall risks. Short-term imports and exports are part of the normal operation of the interconnected markets and play an important role in supporting reliability in the inter-regional context.

For the medium and longer terms, there is scope to secure hydroelectric imports from Quebec, Manitoba and/or Labrador. Like most renewable resource developments, securing these imports would require significant transmission investment. There may also be potential for some non-hydroelectric based imports, including possibly from New York.

1. Introduction

This paper focuses on the status of Supply Resources available to Ontario and is the fourth in a series of eight discussion papers the OPA intends to prepare in developing the Integrated Power System Plan (IPSP). The first and second papers were the Scope and Overview paper (June 29, 2006) and the Load Forecast paper (September 7, 2006) and the third paper was on Conservation and Demand Management (CDM) (September 22, 2006).

1.1 Purpose of this Paper

The purpose of this paper is to guide and support stakeholder engagement that will assist the OPA in the formulation of Supply Resources required for the Integrated Power System Plan (IPSP). The IPSP is a comprehensive 20-year plan for Ontario's electricity system, with a focus on actions that need to be taken in the near and medium term. The Plan will be submitted to the Ontario Energy Board (OEB) in March 2007 for review and approval and will subsequently be updated on a three-year basis.

1.2 Organization of the Paper

In this paper, we describe the generation supply resources available to Ontario for meeting its requirements. Broadly, the available resources comprise the following:

- existing installed generation capacity (hydro, natural gas/oil, coal, nuclear, combined heat and power (CHP), and biomass)
- new renewable resources (hydro, wind, bioenergy including energy from municipal solid waste (MSW))
- new conventional resources (gas, nuclear)
- promising technologies comprising distributed resources such as solar and micro-power technologies (e.g., photovoltaics, fuel cells, micro-CHP, Stirling engines, advanced batteries and superconducting magnetic energy storage systems (SMES) for storage).

In Section 2 we summarize the status and availability of existing generation resources that include "committed procurements" and projects under active development. These are the resources assumed to be available for the purpose of developing the IPSP, subject to the possibility that some of the projects underway may not be completed.

Section 3 describes new renewable resources and their potential and availability in the overall mix.

Section 4 describes new conventional resources and promising technologies, and their potential is described in Section 5.

1.3 Analysis of Environmental Impact and Alternatives

Under paragraph 8 of Section 2(1) of the IPSP regulation (424/04), electricity projects that trigger an individual environmental assessment under Ontario's *Environmental Assessment Act* within five years of the approval of the IPSP require additional analysis. For these projects, OPA is required to provide a "sound rationale" and "an analysis of the impact of the electricity project on the environment, and an analysis of the impact on the environment of a reasonable range of alternatives to the project."

Under Ontario Regulation 116/01 and as summarized in Table 1.1, the supply projects that meet these criteria are waterpower projects that are equal to or greater than 200 MW, oil facilities that are equal to or greater than 5 MW, all coal facilities and certain incineration projects. While there are a number of prospective transmission projects that meet the criteria in regulation 116/01 and meet the five year criterion in regulation 424/04, there are no prospective supply projects that meet these criteria.

Table 1.1 – Electricity Projects Requiring Individual Environmental Assessments

Electricity Project Type	Conditions for Individual Assessment
Transmission lines	> 115 kV and < 500 kV and > 50 km ≥ 500 kV > 2 km
Transformer stations	> 500 kV
Hydroelectric facilities	≥ 200 MW
Oil facilities	≥ 5 MW
Coal facilities	All
Municipal solid waste	Incinerating MSW from ≥ 1,500 persons domestic waste or > 100 tonnes of waste per day
Liquid industrial or hazardous waste	Sites receiving and incinerating off-site generated waste

Source: Ontario Regulation 116/01 and Ministry of Environment, Guide to Environmental Assessment Requirements for Electricity Projects (March 2001). NB: Requests can be made for other electricity projects to be subject to individual environmental assessments.

Notably, nuclear projects are outside the scope of the requirements set out in the IPSP regulation, but nuclear projects are regulated by the Canadian Nuclear Safety Commission and subject to environmental assessment under the *Canadian Environmental Assessment Act*. Under this provision, OPG and Bruce Power are initiating their own processes, whether for nuclear refurbishment or new-build nuclear.

1.4 Request for Stakeholder Comment

This paper is the first step of a four-month process to develop the supply resource components of the IPSP. Throughout this period, we hope to engage stakeholders in a dialogue about research findings, priorities and the work that is emerging on supply planning. Stakeholder comment and advice will help shape the development of this section of the IPSP.

There are several questions embedded in the paper where we seek your assistance and comment. In addition, we seek comment on the following questions:

- Is our understanding of the status and availability of existing and new supply resources consistent with stakeholders' understanding of the subject?
- Are the estimates of potential new resources, renewable and conventional, a good starting place for the development of the first IPSP?
- Are the categories of available resources for the purpose of portfolio development reasonable?
- What further steps, if any, need to be taken to address issues of cost, risk and social and environmental impacts of different resources?
- Are there relevant implementation criteria that should be brought to our attention, based on stakeholders' own experience in the past, or research they have undertaken on specific supply resources in other jurisdictions? What are they, and can supporting documentation be made available?

The consultation process for the supply resources discussion paper will involve a workshop for exchanging information, followed by a web conference, and ending with the submission of the IPSP to the OEB in March, 2007.

For the OPA to give proper consideration to advice and comments from stakeholders and interested parties, submissions must be made in writing and submitted to the OPA through one of the two following channels:

- Electronic submissions can be made through the online form at the following website link, which includes instructions for sending submissions as attachments: http://www.powerauthority.on.ca/ipsp/Page.asp?PageID=751&SiteNodeID=231&BL_ExpandID=155\
- Submissions by regular mail or courier can be sent to: IPSP Submissions, Ontario Power Authority, 120 Adelaide Street West, Suite 1600, Toronto, ON M5H 1T1

Submissions must be received through these channels; given the volume of correspondence, submissions sent to specific individuals at the OPA cannot be assured of review and consideration.

2. Status and Availability of Supply Resources

2.1 Existing Installed Resources

This section summarizes the status of the existing installed supply resources and the availability of supply resources that will be assumed in the IPSP. Table 2.1 shows the total installed capacity of the different generation types in the Ontario system.

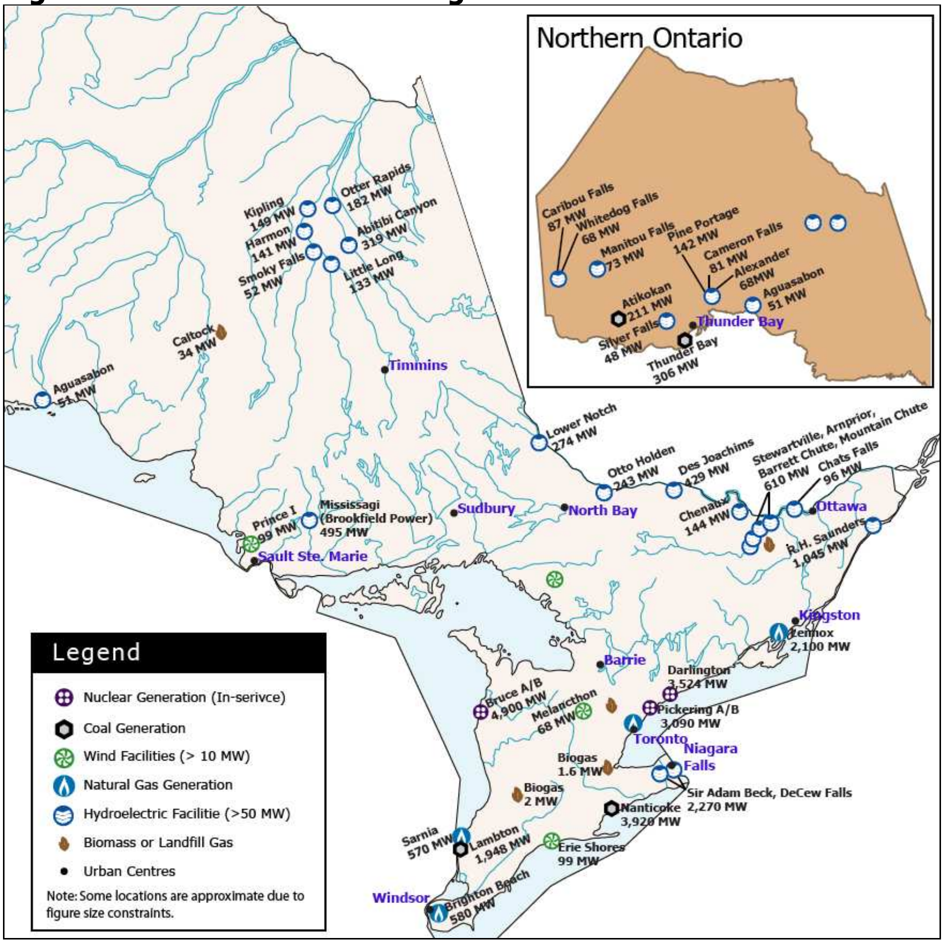
Table 2.1 – Existing Supply Resources in Ontario (October 2006)

Type	Installed Capacity (MW)
Hydroelectric	7,768
Nuclear	11,414
Coal	6,434
Gas/Oil-Fired	5,103
Wind	305
Biomass	70
Total	31,094

Source: IESO, 18 month Outlook, October 2, 2006

Figure 2.1 shows the location of existing generation facilities in Ontario.

Figure 2.1 – Location of Existing Generation Facilities in Ontario



Source: OPA

2.2 Status and Availability of Existing Resources

In this section, we summarize the availability of existing resources, taking into consideration committed procurements, new analysis of the expected amount of hydroelectric capacity available to meet the annual system peak, declining nuclear capacity due to indicated retirements, the replacement of coal-fired generation units, and changes related to non-utility generation (NUG) contracts that are due to expire.

2.2.1 Hydroelectric Generation

Electricity from water has been a substantial component of the total power generation capacity in the Province of Ontario for more than a hundred years and will continue to be so in the future. The current installed hydroelectric capacity of 7,768 MW (see Table 2.1) represents approximately 25 percent of Ontario's total installed generation capacity. In a median year, electricity production from hydroelectric generation is of the order of 34 to 37 TWh (terawatt hours). Besides being a renewable resource, hydroelectric generation is very flexible and valuable since the total hydroelectric energy production pattern can be scheduled to match that of the total Ontario energy demand in a typical day.

A number of hydroelectric plants can store potential energy in the form of water in their forebay during times of low demand i.e., overnight. They are able to produce electric power from that water very quickly when required, for example, during morning load pickup, and at high rates of 3,000 MW per hour or more.

While the operating flexibility of hydroelectric resources has always been of value, its importance will increase in the future as load patterns and supply mix change, particularly as intermittent generation resources such as wind become a more significant component of Ontario's electricity system. The operating flexibility of hydroelectric resources is limited by water storage capability and hydroelectric generators would need to be compensated for foregoing revenues at time of peak load to provide this flexibility.

Considering the important contribution of hydroelectric resources, and in response to the experience of the summer of 2005,[1] the OPA, in conjunction with the Independent Electricity System Operator (IESO) and market participants, have reviewed the expected contribution attributable to Ontario’s hydroelectric resources in meeting system peak load. This review concluded that, for planning purposes, a forecast based on median historical values of production at the time of the system peak would provide a more accurate forecast of hydroelectric capacity.

Traditionally, hydroelectric capacity forecasts are based on individual hydroelectric unit capacity with allowances for outages (planned and forced). Simple arithmetic summation of the individual capacity ratings results in what is known as the non-coincident hydroelectric capacity. This is likely to overstate the true coincident capacity, particularly at the time of system peak load, even after allowances are made for the varying performance and reliability of the individual hydroelectric units. In this document, hydroelectric load meeting capacity at the time of the system peak is used.

To determine the capacity of existing hydroelectric stations, excluding hydroelectric non-utility generators, OPA completed the following analysis:

- used 10 years (1996-2005) of historical hourly hydroelectric production profiles from Ontario generators
- aggregated these production profiles to arrive at a system hydroelectric production profile
- determined the system hydroelectric capability coincident with the hour of the system peak. The hours when the system peak occurred are shown in Table 2.2 along with the coincident hydroelectric capability.

[1] In 2005, hot weather conditions caused record electricity demands through increased air conditioner use, and drought-like conditions that limited available hydroelectric energy to meet those demands. In particular, this experience focused attention on the ability of hydroelectric plants to maintain output for extended periods, both during a day and over several successive days.

- calculated the 10-year mean of the hydroelectric capability coincident with the system peak (5,459 MW)
- added 500 MW of hydroelectric reserve to the mean hydroelectric capability coincident with system peak. Historically, there has been 500 MW of hydroelectric reserve accepted by the IESO during the hour of system peak in the reserve markets.
- out of the existing 7,768 MW of installed hydroelectric capacity, 5,959 MW of it will therefore be considered the expected capacity available at the time of summer peak. We propose to use this assumption for capacity planning in the development of the IPSP.

Table 2.2 – Hydroelectric Production Coincident with System Peak

Year	Peak Day	Peak Load Hour	Hydro Contribution (MW)
1996	Aug 7	17	5,943
1997	July 14	16	5,652
1998	July 15	16	5,061
1999	July 5	16	5,766
2000	Aug 31	16	5,651
2001	Aug 8	16	5,297
2002	Aug 13	14	5,304
2003	Jun 26	16	5,151
2004	July 22	16	5,775
2005	July 13	16	4,986
		Average	5,459

*The mean hydro at Summer Peak used in the OPA load and capacity tables throughout the paper only includes values from 1996 to 2005 as the 2006 peak values were unavailable at the time of analysis.
Source: OPA

2.2.2 Nuclear Generation

Twenty nuclear units were placed into service in Ontario between 1971 and 1992. Sixteen of these units are currently in operation, totaling 11,400 MW of capacity corresponding to approximately 37 percent of Ontario's total installed generation capacity. In 2005, Ontario's nuclear facilities produced approximately half of the province's electricity. The corresponding total cumulative electricity produced from these facilities since they were placed in-service amounts to over 1800 TWh. Table 2.3 provides a comprehensive summary of the performance of Ontario's nuclear units since they were placed in-service and Table 2.4 summarizes the cumulative used nuclear fuel in storage arising from nuclear generation in Ontario. The annual performance of each unit in terms of capability factor (percentage) is illustrated in Figure 2.2 for full years of commercial operation where the units were planned to be in operation and an operating license was in effect.

Table 2.3 – Performance of Ontario's Nuclear Units Since In-Service (Capability Factor, %)

Year	Pickering A	Pickering B	Darlington	Bruce A	Bruce B
1971	66.13				
1972	47.93				
1973	82.51				
1974	74.54				
1975	62.06				
1976	86.89				
1977	90.77			28.68	
1978	88.09			72.34	
1979	86.56			79.46	
1980	82.63			86.82	
1981	88.16			91.20	
1982	86.80	7.50		86.43	
1983	75.88	55.28		89.45	
1984	41.11	73.40		93.71	67.62
1985	34.82	81.17		83.24	86.25
1986	38.38	82.88		75.08	86.19
1987	44.42	86.37		65.28	84.80
1988	64.43	93.40		62.24	84.82
1989	59.03	83.43		54.14	88.31
1990	40.34	76.91	91.82	48.01	80.77
1991	55.63	89.19	14.29	63.69	88.02
1992	61.60	73.60	58.08	55.51	78.46
1993	81.11	81.51	80.82	33.53	66.63
1994	72.30	84.73	87.19	47.56	79.99
1995	42.08	82.76	90.08	54.42	77.08
1996	36.22	49.60	84.51	57.95	82.87
1997	56.44	58.67	60.42	44.32	78.61
1998	Not I/S	73.00	85.59	47.50	70.48
1999	Not I/S	76.35	82.57	Not I/S	81.88
2000	Not I/S	56.18	86.13	Not I/S	84.12
2001	Not I/S	72.43	84.94	Not I/S	86.82
2002	Not I/S	80.23	89.49	Not I/S	75.86
2003	69.75	67.04	80.91	Not I/S	86.25
2004	72.10	69.42	86.09	79.92	84.54
2005	82.68	76.65	89.75	79.46	80.89
Lifetime Average	65.71	72.15	78.29	65.83	80.96

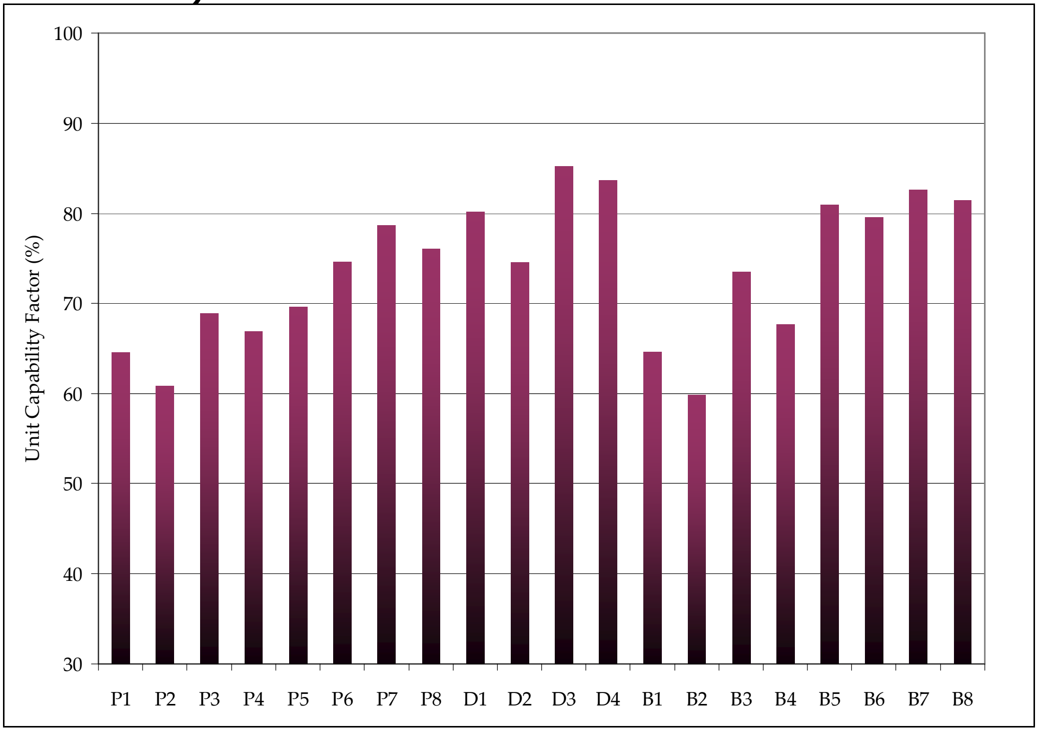
Source: Reactor yearly data from IAEA 2005 Operating Experience with Nuclear Power Stations (Power Reactor Information System).

Table 2.4 – Used Nuclear Fuel In Storage (to December 2004)

Storage Location	Licensee	Bundles in Reactor(s)	Bundles in Wet Storage	Bundles in Dry Storage	Total Fuel Bundles
Bruce A	Bruce Power[1]	12,480	361,271		373,751
Bruce B	Bruce Power[1]	24,575	369,344	29,184	423,103
Pickering	OPG	36,744	382,332	135,927	555,003
Darlington	OPG	24,960	256,068		281,028
Douglas Point	AECL[2]			22,256	22,256
Chalk River	AECL[3]			4,853	4,853
Gentilly 1	AECL[4]			3,213	3,213
Gentilly 2	HQ	4,560	33,814	60,000	98,374
Pt. Lepreau	NBP	4,560	39,482	63,180	107,222
Whiteshell	AECL[5]		360	360	360
Total		107,879	1,442,311	318,973	1,869,163

1. OPG manages used fuel produced by Bruce Power which leases the Bruce reactors from OPG.
2. The Douglas Point Nuclear Generating Station in Kincardine, Ontario was shut down in 1986.
3. Chalk River Laboratories (CRL), near Deep River, Ontario is a nuclear research facility with test reactors, fuel inspection and other facilities. Most of the used fuel bundles in the CRL dry storage area are from the Nuclear Power Demonstration (NPD) reactor which was de-fueled in 1987. A quantity of non-standard fuel waste is also stored at the CRL.
4. Gentilly 1, at Becancour, Quebec was shut down in 1977.
5. The dry storage facility at Whiteshell, Manitoba houses research reactor fuel rods and some used fuel bundles from the shut-down Douglas Point reactor.
Source: NWMO, Choosing A Way Forward, Nov 2005.

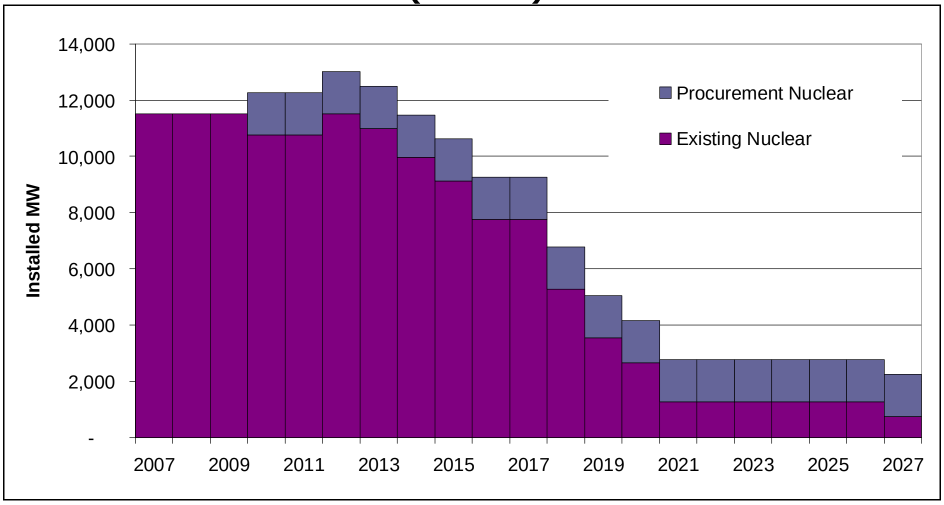
Figure 2.2 – Lifetime Operational Performance (Unit Capability Factor, %) for all Ontario Units



This indicates performance for full years of commercial operation from in-service to 2005 (i.e., excluding those years units were taken out of service for an extended outage due to plant condition). Additional information on nuclear performance is discussed in Section 4.
Source: IAEA 2005 Operating Experience with Nuclear Power Stations (Power Reactor Information System).

Figure 2.3 shows the installed nuclear capacity including the planned refurbishments at Bruce A that are considered part of the existing nuclear capacity. Additional supply from nuclear refurbishments and new nuclear units is discussed further in Section 4.

Figure 2.3 – Installed Nuclear Capacity Including Planned Refurbishments (Bruce A)



Source: OPA

2.2.3 Coal

As part of the directive issued by the Minister of Energy on June 13th, 2006 to prepare an IPSP, the OPA was directed to:

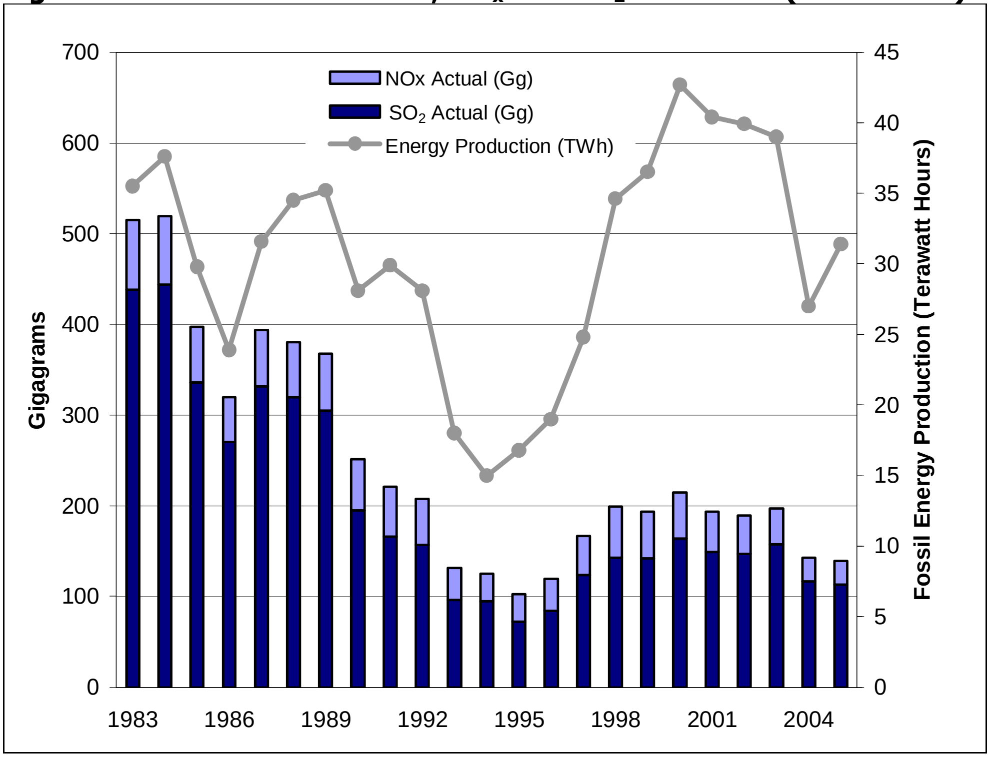
> *"Plan for coal-fired generation in Ontario to be replaced by cleaner sources in the earliest practical time frame that ensures adequate generating capacity and electric system reliability in Ontario. The OPA should work closely with the IESO to propose a schedule for the replacement of coal-fired generation, taking into account feasible in-service dates for replacement generation and necessary transmission infrastructure."*

In response to the Minister's June 13th directive, the OPA has performed assessments in order to develop a plan to guide the replacement of existing coal-fired generation as quickly as possible while ensuring the adequacy and reliability of Ontario's electric system.

The current installed coal-fired generation capacity in Ontario is 6,434 MW which represents 21 percent of the total installed capacity in Ontario (2005). The corresponding electricity produced from this generation source was 30.9 TWh or 19 percent of the total electricity production in 2005.

Figure 2.4 shows the historical annual electricity production from fossil generation (mainly coal-fired plus the oil/gas-fired Lennox station) and the corresponding SO_2 and NO_x (oxides of sulphur and nitrogen) emissions from 1983-2005. Also included in the data are contributions from the coal-fired Lakeview station which was removed from service in 2005.

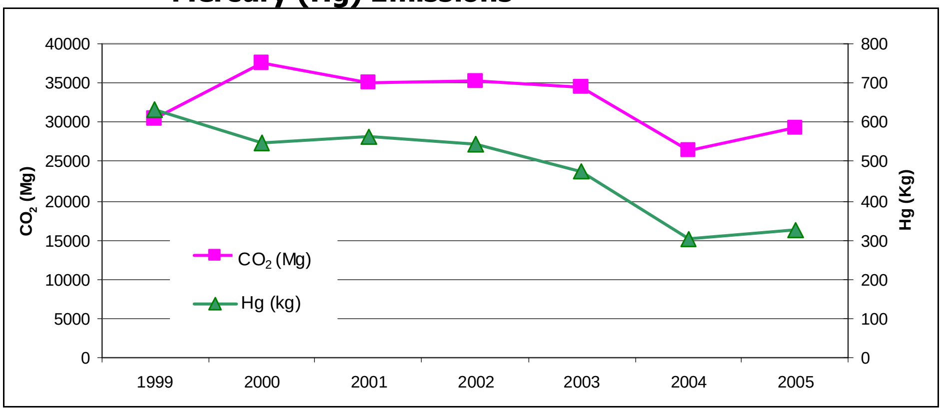
Figure 2.4 – Fossil Generation, NO_x and SO_2 Emissions (1983-2005)



Source: OPG

Figure 2.5 shows the corresponding total CO_2 (carbon dioxide) and Hg (mercury) emissions from the coal-fired stations over the period 1999-2005.

Figure 2.5 – Coal-Fired Generation, Carbon Dioxide (CO_2) and Mercury (Hg) Emissions

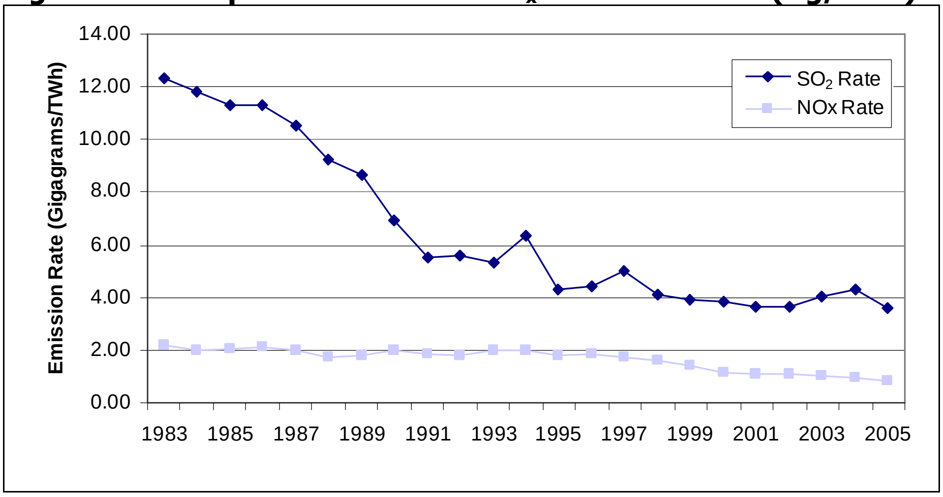


Source: OPA (based on OPG data)

Over the years, OPG has retrofitted a number of its coal-fired generation units with emissions control technology which has resulted in reduced emissions from these facilities. These include

Flue Gas Desulphurization (FGD) or "scrubbers" for SO_2 removal and Selective Catalytic Reduction (SCR) for NO_x removal. Combined they also help reduce mercury emissions. Figure 2.6 shows the historical decline in SO_2 and NO_x emission rates (Gigagrams/TWh) during the period 1983-2005 from fossil generation in Ontario.

Figure 2.6 – Sulphur Dioxide and NO_x Emission Rates (Gg/TWh)



Source: OPG

The Role of Existing Coal-fired Generation

The current installed coal-fired generation in Ontario is an important component of the present supply mix. Besides providing capacity and electricity, these facilities are also important in 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. In some cases, the coal-fired units play an important role in maintaining the reliability of supply to local areas. The coal replacement plan and its integration in the overall power system for the relevant time frame is further discussed in the paper titled "Integrating the Elements – A Preliminary Plan" (discussion paper #7).

2.2.4 Gas and Oil-Fired Generation

The current installed capacity of gas and oil generation is 5,103 MW as shown in Table 2.1. The near-term potential consists of committed procurements of gas generation with an additional 2,250 MW of uncommitted (pending procurements).

Most of the gas procurements are planned to be in-service by 2010, if all of the committed and pending procurements come into service. Combined with existing gas/oil capacity, Ontario is expected to have approximately 9,300 MW of installed gas/oil capacity by 2010, and nearly 11,000 MW by 2012.

The June 13th, 2006 Minister's directive has accepted OPA's advice on a "smart gas strategy" that will ensure that Ontario's supply mix not include significantly more natural gas-fired generation than has already been contemplated by procurement. All future gas developments (i.e., beyond those listed above as under procurement) will be planned in accordance with the smart gas strategy. One way in which this might be accomplished would be to coordinate any future gas developments with local area reliability initiatives when gas-fired generation is the most economic alternative to alleviate the reliability concerns. 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). For example, Lennox has been identified by the IESO as a critical resource for area reliability and has been operated on the basis of "Reliability-Must-Run" contracts. The requirement for continued operation of Lennox in the future will be considered in the IPSP.

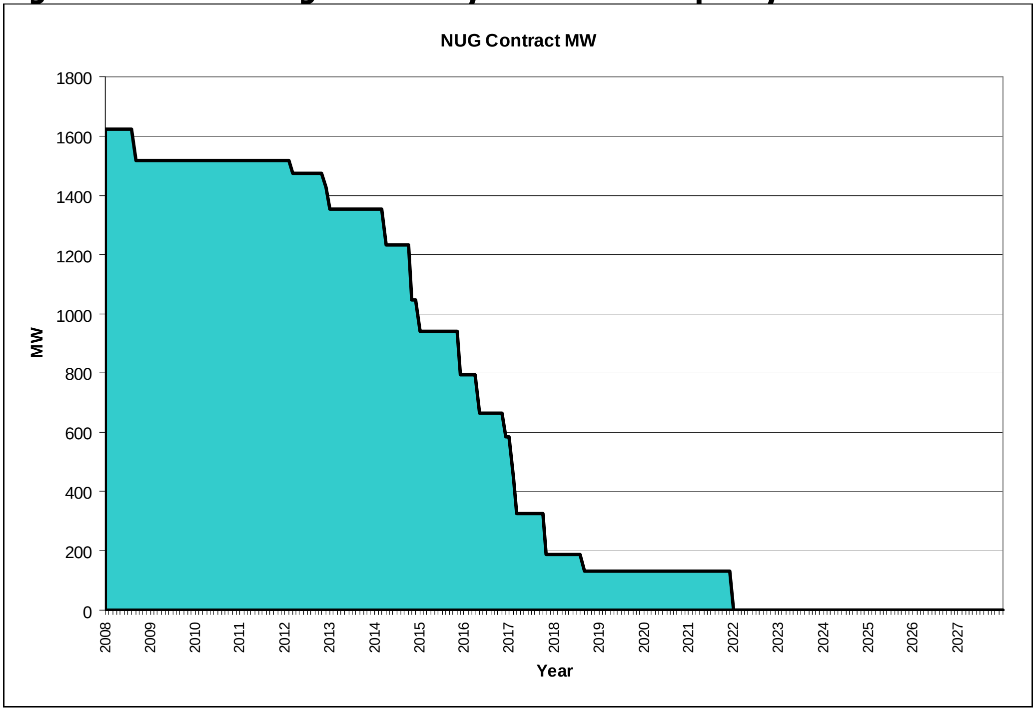
Non-Utility Generation (NUG)

In the late 1980s and early 1990s, Ontario Hydro entered into approximately 90 Power Purchase Agreements (PPAs) with generators that were not owned by the utility (NUGs). The major portion of this generation is gas-fired. Approximately 23 of these contracts continue to be managed by the Ontario Electricity Finance Corporation (OEFC). The contracts expire throughout the period to 2048. A number of the revised contracts representing well over 1,000 MW will expire within the study period (i.e., by 2028).

For present purposes, it is assumed that the NUGs will have the ability to continue operation after their Power Purchase Agreements expire. There are 29 non-utility generators in Ontario representing 1,722 MW of installed capacity. Of the 29 facilities, five are cogeneration facilities.

Figure 2.7 shows the declining NUG contract capacity.

Figure 2.7 – Declining Non-Utility Generation Capacity Under Contract



Source: OPA, Ministry of Finance.

Combined Heat and Power (CHP)

There are 110 CHP facilities in Ontario representing roughly 2,300 MW of installed capacity. Of the 110 facilities, 82 are natural gas fired and the remaining are biomass. Of the 82 natural gas facilities in-service, only nine sell all their power to the grid, 13 sell some of their power to the grid, and 60 facilities are not connected to the grid.[2]

2.2.5 Wind

The currently installed capacity of wind generation in Ontario is 305 MW comprising the following major projects:

- Kingsbridge 1 (40 MW)
- Port Burwell (formerly Erie Shores) (99 MW)
- Prince 1 (99 MW)
- Amaranth (formerly Melanchton 1) (68 MW)

Committed procurements and near-term potential comprise an additional 955 MW of wind power capacity.

[2] Source: Simon Fraser University Cogeneration Database, http://www.cieedac.sfu.ca/CIEEDACweb/mod.php?mod=cogeneration&menu=1604

2.2.6 Biomass

The currently installed capacity of biomass-based generation in Ontario is 70 MW. Recent committed procurements by OPA will add another 10 MW that includes the following projects:

- Biogas Hamilton Cogen (2 MW)
- Eastview Landfill (3 MW)
- Trail Road Landfill (5 MW).

2.3 Summary of Available Resources

The availability of resources which we propose to include for consideration in the IPSP are grouped according to the following criteria:

Near-Term Potential are resources which meet the following criteria:

1. technical and commercial feasibility is known and established (high confidence level)
2. schedule and in-service dates are predictable (resource can be in-service by the end of 2015 with high confidence level)
3. all known developments (whether committed procurements or under active development by market participants) can be considered a reasonably assured resource available in the near-term for planning purposes
4. regulatory issues are understood, implementable and considered manageable (resource can be in-service by the end of 2015 with high level of confidence).

If a resource, in OPA's judgment, does not currently meet the above criteria, but can reasonably be expected to do so in the future, it is categorized as a "Future Potential Resource":

Future Potential Resources are resources which meet the following criteria:

5. technically feasible but not yet commercially proven (high confidence for implementation after 2015)
6. schedule and in-service dates not predictable with confidence (low confidence prior to 2016 but increasing levels of confidence within the 2016 to 2027 time frame)
7. regulatory issues and implementation barriers judged to be significant for implementation and in-service prior to 2016.

A summary of the available supply resources by type and their near-term and future potential appears in Table 2.5. Of the identified near-term potential, approximately 51 percent is committed under procurement or is under development and this is shown in Table 2.6. The near-term potential identified as uncommitted (approximately 49 percent) will become a primary focus of attention and development of the near-term action plans which we propose to base the IPSP on.

Table 2.5 – Potential Supply Resources

Resource Type	Near-Term Potential (2015) (MW)	Future Potential (2027) (MW)	Total (MW)
Renewable Energy			
Hydroelectric	730	2,270*	3,000
Wind	2,460	6,240	8,700
Biomass	300	950	1,250
Subtotal	3,490	9,460	12,950
Nuclear	2,020	10,360	12,380
Natural gas	5,520	see note a	5,520
Cogeneration/CHP	1,000	see note b	1,000
Gasification	--	250	250
Promising Technologies			
Solar	50	50	100
Micro CHP/Fuel Cells	100	400	500
Generation Storage		1,000	1,000
Subtotal	150	1,450	1,600
Total	12,180	21,520	33,700

*Approximately 200-300 MW of hydroelectric capacity identified under the future potential could be developed in the near-term based on projected in-service dates.
Note a: The role of natural gas is consistent with OPA's "smart gas strategy". Its further potential and increased role are dependent on gas prices.
Note b: Additional potential of cogeneration/CHP is dependent on gas prices and development of the necessary infrastructure in high density/urban areas.
Source: OPA

Table 2.6 – Committed Procurements as a Proportion of Near-Term Potential

Resource Type	Near-Term Potential (MW)	Committed Near-Term Potential		Un-Committed Near-Term Potential	
		(MW)	(%)	(MW)	(%)
Renewable Energy					
Hydroelectric	730	43	6%	687	94%
Wind	2,460	955	39%	1,505	61%
Biomass	300	5	2%	295	98%
Subtotal	3,490	1,003	29%	2,487	71%
Nuclear	2,020	1,500	74%	520	26%
Natural gas	5,520	3,265	59%	2,255	41%
Cogeneration/CHP	1,000	416	42%	584	58%
Gasification	--	--	--	--	--
Promising Technologies					
Solar	50			50	100%
Micro-CHP/Fuel Cells	100			100	100%
Generation Storage					
Subtotal	150			150	100%
Total	12,180	6,184	51%	5,996	49%

Source: OPA

A detailed discussion of the future potential resources available to Ontario, including new renewable resources and new conventional resources is provided in Sections 3 and 4.

3. New Renewable Resources

This section provides an overview of the potential for new renewable resources that will be considered in the development of the IPSP and provides new information that will provide guidance to developers of new generation facilities.

In the IPSP, we propose to refine the estimates of renewable generation potential given in the supply mix advice in light of new information, and develop an implementation plan for the integration of renewable energy sources into the provincial power system. During stakeholder consultations, we are seeking advice and input on the size, sources and locations of available renewable energy, operational issues associated with large-scale renewable energy developments, and overall strategy for incorporating renewable generation into the transmission grid. The renewable energy sources include: (i) hydroelectric, (ii) wind, and (iii) bioenergy. Promising technologies comprising distributed resources such as solar photovoltaics (PV), fuel cells, and micro-power technologies that enable combined heat and power (CHP) at customer sites (i.e., micro-turbines, Stirling engines, biogas digesters) are described in Section 5.

A substantial portion of potential large-scale (greater than 10 MW) new hydroelectric, wind and biomass resources is located in northern and rural southern Ontario, distant from the growing load centres in urban southern Ontario, and often far from transmission corridors. The integration of such resources therefore becomes an important consideration.

3.1 Hydroelectric

Recent Information and Analysis

OPA has conducted a thorough review of existing hydroelectric resources in the province as well as a more detailed assessment of future potential at undeveloped sites. This section summarizes the results and provides initial guidance and useful information about the potential for development of specific sites and regions of Ontario.

The results of these assessments, for both the existing and the undeveloped hydroelectric potential, were categorized as follows:

- **Currently Installed Hydroelectric**: This category refers to the currently installed (2006) hydroelectric resource base of 7,768 MW with a corresponding annual median energy production of 34 to 37 TWh.

- **Near-Term Potential**: This category includes capacity and energy additions (through rehabilitations, efficiency upgrades, extensions or redevelopments), either in progress or planned, at existing hydroelectric facilities or at existing sites. Included also are new generation developments (active or planned) at greenfield sites.
- **Future Potential**: This category includes those sites with practical potential for future development and that meet the general screening criteria applied by OPA.
- **Future Potential (Constrained)**: The sites identified under this category are generally sites which have hydroelectric potential but are currently constrained from development.

Compared to the OPA *Supply Mix Background Reports* (December 2005), essentially the same potential hydroelectric sites were identified, with the following changes:

- The Renison site (135 MW) located in the Moose River Basin is now included as a practical site in the Future Potential category.
- Two Northern Rivers' sites, Hat Island (490 MW) and Chard (370 MW) on the Albany River, are included in the Future Potential category. It should be noted that these sites are currently subject to the Northern Rivers Commitment restricting development over 25 MW.
- OPA has performed a preliminary assessment of the potential for and possible system benefits of pumped generation storage (PGS). The results of this assessment are discussed in Section 4.3 on Storage.
- Potential sites subject to policy-based criteria, e.g., sites within provincial/national parks or protected areas, were deemed non-practical and were therefore excluded. They are identified under the Future Potential (Constrained) category. Potential sites whose development was deemed impractical based on past studies were also excluded.
- Finally, sites whose capacity rating is less than 1 MW are not explicitly included in the detailed inventory of resources. Rather, an allowance of 30 MW has been made to account for that entire segment of waterpower resources in the Future Potential category.

3.1.1 Hydroelectric Resources and Future Potential

Table 3.1 – Hydroelectric Resources and Additional Potential in Ontario

Category	Capacity (MW)	Energy (GWh)
Currently-installed	7,768	34,000-37,000
Near-term Potential	728	3,557
Future Potential (includes allowance of 30 MW and 195 GWh for micro sites (1 MW or less))	2,296	7,009
Total Conventional Hydroelectric Potential:	10,792	44,566-47,566
Future Potential (Constrained)	1,076	3,847

Source: OPA

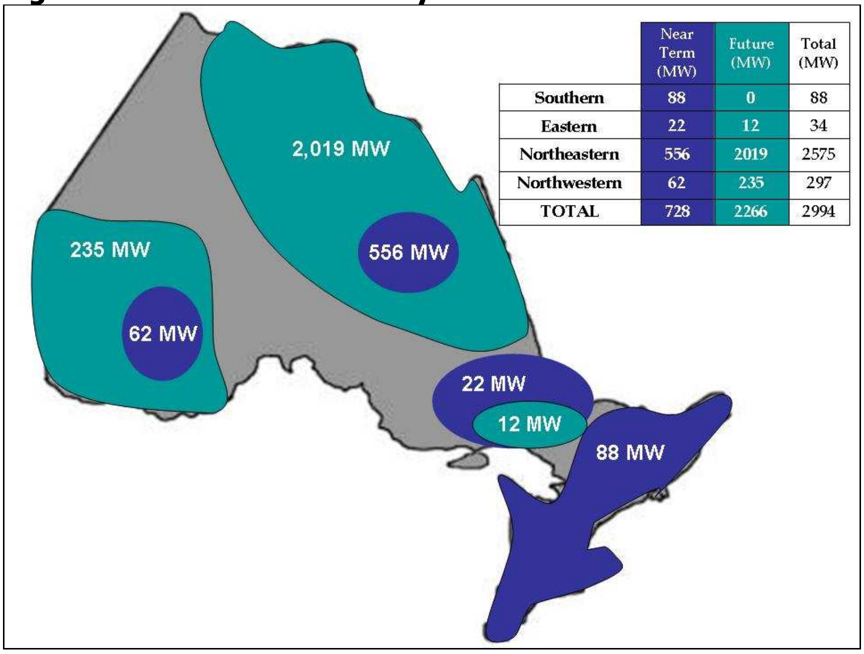
Table 3.1 is a summary and overview of the OPA assessment results. Details of the various categories, except for the existing hydroelectric capacity, are discussed next.

By 2014-2015, the projects or developments under the Near-Term Potential category are projected to add about 700 MW to the currently installed hydroelectric capacity of 7,768 MW with a corresponding median energy contribution of 3,500 GWh. The bulk of these projects are expected to be in-service by 2010-2011, with the remainder completed by 2014-2015. Table 3.2 lists the various projects and their projected contributions included in this category. OPA is reasonably confident that these projects and their corresponding potential will be realized in the near term.

The hydroelectric potential in the Future Potential category, that is undeveloped but considered practical, represents a sizeable component that could add another 2,200 MW of capacity and about 7,000 GWh to the system within the IPSP plan period. Table 3.3 lists the sites and their potential that were included in this category. OPA has adopted a conservative approach in developing this information and the full hydroelectric potential under this category could be higher. Most of the sites that are listed are located in remote areas of northern Ontario (northeast, northwest, northern, e.g., Albany River) and will likely require significant transmission infrastructure upgrades. From a practical standpoint, their full development potential is projected to be realized in the period from 2015-2025. Based on the possible in-service dates identified in the table, a number of these developments, with an aggregate potential of about 200 to 300 MW, could potentially be developed by 2015-2016. With the exception of the Lower Mattagami sites (Little Long, Harmon, Kipling and Smoky Falls) listed in the Near-Term Potential category, all other future potential hydroelectric developments in the Moose River Basin are subject to a Co-planning Framework with affected First Nations.

The near-term and future potential hydroelectric resources in Ontario by region and size of resource are shown in Figure 3.1 The majority of new future potential supply resources are located in the northeastern and rural parts of the province while the Greater Toronto Area and surrounding Greater Golden Horseshoe represent centres of load growth and demand. This puts a large emphasis on close coordination and effective integration of resource development with transmission development. These aspects are discussed further in the papers on transmission (discussion paper #5) and integration (discussion paper #7).

Figure 3.1 – New Potential Hydroelectric Resources



	Near Term (MW)	Future (MW)	Total (MW)
Southern	88	0	88
Eastern	22	12	34
Northeastern	556	2019	2575
Northwestern	62	235	297
TOTAL	728	2266	2994

Source: OPA

Table 3.2 – Near-Term Potential

River	Station(s)	Nature/ Status of Work *		Capacity (MW)	Energy (GWh)	Projected In-Service	Remarks
Southern Ontario							
Muskoka	North Bala	N/	C	4	21	2012	In pre-feasibility phase
Niagara	Sir Adam Beck No.1	RH/	R	36	170	2008-2014	Includes the conversion of remaining 25 Hz units to 60 Hz
	Niagara Tunnel	N/	IP	0	1,600	2009	Tunnel Construction is underway
Trent	Trent University	N/	C	6	34	2009	EA initiated
	Healey Falls, Ranney Falls	EX/	R	12	45	2009-2010	
Welland	DeCew Falls- NF23	RH/	C	18	44	2014-15	
	Schikluna, Gibson	N/	R	12	72	2009-2011	
Eastern Ontario							
Madawaska	Mountain Chute	RH/	R	8	8	2011-2012	
Ottawa	Chaudiere	RD/	C	7	26	2011	Redevelopment of existing station site
	Otto Holden	RH/		4	11	2012-2015	
Rideau	Rideau Falls	RD/	C	2	7	2008	
South Nation	Casselman	N/	C	1	4	2012	
Northeastern Ontario							
Abitibi	Abitibi Canyon	RH/	IP	20	10	2006-2007	10 MW already in-service
	Otter Rapids	N/	S	10	25	2012-2013	
Kapuskasing	Big Beaver Falls	N/	A	11	58	2012	In pre-feasibility phase
Mattagami	Little Long, Harmon, Kipling, Smoky Falls	EX RD/	R	450	826	2011	Includes redevelopment of existing Smoky Falls station site
	Yellow/Island Falls	N/	C	18	95	2013	EA initiated
	Lower Sturgeon, Sandy Falls, Wawaitin	RD/	R	16	69	2009	Incremental capacity and energy additions
	Mattagami Lake Dam	N/	S	5	24	2010	
Montreal	Ragged Chute	RD/	C	4	14	2006	EA initiated
	Hound Chute	RD/	R	6	23	2009	Incremental capacity and energy additions
Spanish	Espanola	N/	C	16	116	2006	
Northwestern Ontario							
Aguasabon	Mileage19.2/25.6	N	C	10	53	2012	
	Long Lake Dam	N/	S	7	34	2011	
English	Lac Seul	RD/	C	13	51	2007-2008	Redevelopment of Ear Falls site
Nipigon	Cameron Falls, Alexander, Pine Portage	RH/	C	9	37	2007-2011	
White River	Umbata Falls	N/	C	23	81	2008	Released by OPA/MOEn through its public bidding process
	Total Near-Term Potential			728	3,557		

Note:*N = New; RD = Redevelopment; RH = Rehabilitation; EX = Extension; C= Committed; R = Under Review; S = Under Study; A = Application Made; IP = Underway
Source: OPA

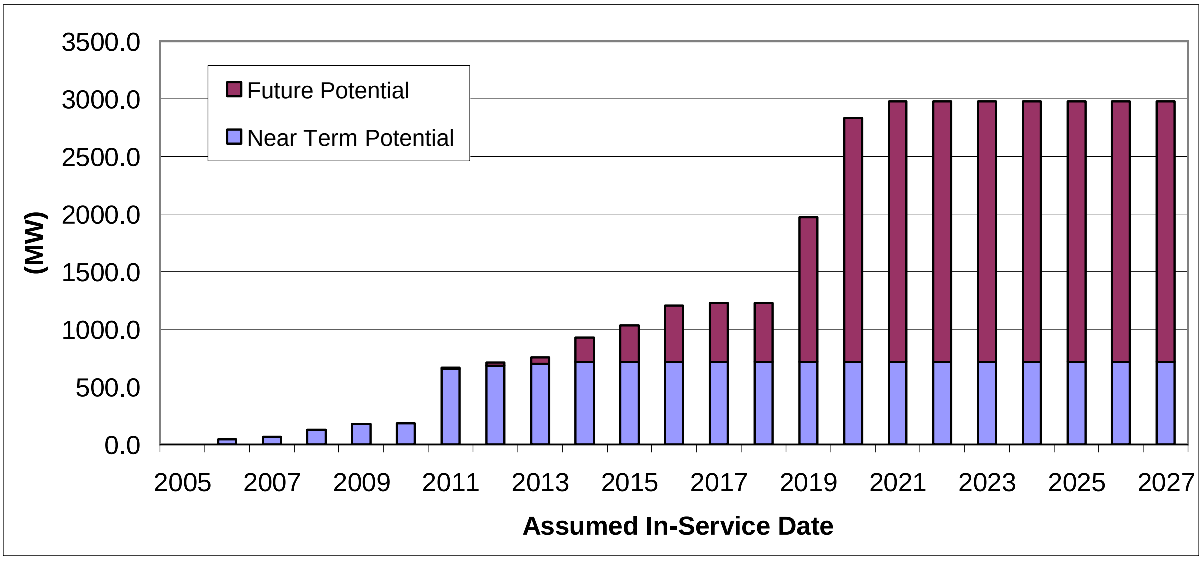
Table 3.3 – Future Potential

River	Site/Station	Capacity (MW)	Energy (GWh)	Possible In-Service
Eastern Ontario				
Madawaska	Bark Lake Dam	4	21	2015
Magnetawan	Bying Inlet	4	23	2015
	Lower Burnt Chute	3	16	2014
Northeastern Ontario				
Abitibi	Allan Rapids, Black Smith Rapids, Nine Mile Rapids, Sand Rapids, Sextent Rapids	711	1,894	2019-2023
Albany	Hat Island, Chard *	860	2,600	2020-2022
Amable du Fond	Gravelle Chute	3		2011
Englehart River	Larder	7	37	2012
Frederickhouse	Frederick House Lake Dam	4	21	2015
	Neelands Rapids, Twp. of Fournier Rapids, Twp. of S. Clute and Leitch, Wanatango Falls, Twp. of Mann	15	40	2019-2020
Grassy River	Timmins South	4	21	2012
Groundhog River	Wakusini (2 sites)	3	14	2020
Mattagami	Grand Rapids	174	457	2016
	Poplar	7	17	2021
Montreal	Lady Evelyn Lake Dam, Mistinikon Lake Dam	6	28	2011
Moose River	Renison	135	355	2021
Opasatika	Opasatika Rapids, Breakneck Falls, Christopher Rapids, Mariva Falls	19	34	2017-2018
Pic River	Manitou Falls	58	254	2015
Serpent	Mccarthy Chute	2		2018
Sturgeon	Red Cedar Lake Dam	2	10	2015
Wanapitei	Wanapitei Lake Dam	2	8	2011
	Km 4.8- Mcvittie S	2	6	2014
Whitefish	Below Cross Lake, Lang Lake (La Cloche Mts.)	6	24	2020
Northwestern Ontario				
Aguasabon	Lower Lake	10	61	2015
Black Sturgeon	At Hwy 17	3	15	2011
Current River	Throwbridge Falls, N. Thunder Bay, Bentley Creek	4	23	2012
Kaministiquia	Hume, Lot 2 Block 'A' Twp. Paipoonge, Mokoman Falls, Shabaqua Corners	24	64	2013
Little Jackfish	Mileage 7.9	132	570	2014-2015
Namakan	Myrtle Falls, Hay Rapids/High Falls	18	63	2014-2015
Namewaminikan	Km 8 & km 12.8 (combined) Dragonfly Lake, High Falls	24	85	2015-2016
White	1.6 km below Chicagonce Falls, 3.2 km below White Lake	20	53	2019-2020
Total Future Potential		2,266	6,814	

*Note: These sites are currently subject to the Northern Rivers Commitment (i.e., no development over 25 MW)
Source: OPA

The combined capacity additions from these two categories (Near-Term Potential and Future Potential) could therefore be of the order of 3,000 MW during the 20-year planning horizon of the IPSP, with a corresponding energy production of up to 10,000 GWh. Figure 3.2 illustrates the potential capacity additions over time from these resources assuming full implementation by the projected in-service dates.

Figure 3.2 – Near-Term and Future Hydroelectric Potential (In-Service)



Note: earliest probable in-service dates are used.
Source: OPA

Table 3.4 identifies the sites that were included under the Future Potential (Constrained) category. While these sites represent a combined total capacity of about 1,100 MW with a corresponding energy production of 4,000 GWh, OPA will not be including them in the resource base at this time in developing the IPSP. This decision will be reviewed as necessary pending future government policy direction or changes concerning these sites.

Table 3.4 – Future Potential (Constrained)

River	Site/Station	Location	Capacity (MW)	Energy (GWh)	Remarks
Eastern Ontario					
Madawaska	Highland Falls	In a Park	10	53	
Petawawa	Crooked Rapids		3	13	
Northeastern Ontario					
Abitibi	Coral Rapids	In a Park	192	505	
French River	Lower Chaudiere Falls, Five Mile Rapids		24	63	
French River	Dalles	In a Park	17	45	
Little Pic River	Near Mouth	In a Park	2	6	
Magnetawan	Farm Rapids	In a Park	3	16	
Mattagami	Cypress Falls	In a Park	42	111	
Missinaibi	(Various)	In a Park	214	1,125	
Mississagi River	Patten Post	In a Park	250	876	Managed river, with existing operating stations North and South of the site
Moose River	Grey Goose	In a Park	140	369	
Newpost Creek	At Parliament		6	26	
Newpost Creek	At the mouth	In a Park	27	118	
North French River	First Rapids, Nettogami Island		12	32	Federal land, water supply to village
Northwestern Ontario					
English River	Mackenzie Lake, Upper Oak Falls, Maynard Falls	In a Park	67	177	Controlled by Lake of the Woods Control Board
Groundhog River	Whist Falls, 16 Km Rapids Twps Hicks, Stringer & Mcvicar, Upper & Lower Ten Mile Rapids	In a Park	48	252	
Nettogami	Nettogami Falls	In a Park	12	38	
Seine	Island Falls + Rapids		2	9	
Vermilion	Cascade Falls, Soo Crossing		3	13	
Total Constrained Future Potential			1,076	3,847	

Source: OPA

3.1.2 Hydroelectric Plant Costs and Schedules

We have conducted a preliminary analysis of illustrative unit energy costs for future new hydroelectric plants located in northern Ontario. The rationale for this is that the majority of the undeveloped sites, and their corresponding potential considered practical for future development, are located in northern Ontario (see Table 3.3). Based on this analysis, we estimate that unit energy costs for new hydroelectric plants at these northern sites will be in the order of 8-10 cents per kWh or higher. These costs include capital, operation, maintenance and administration (OM&A) and connection costs, but exclude area transmission infrastructure upgrades that may be required. The unit energy costs for the hydroelectric developments identified in the Near-Term Potential category will be substantially lower for projects involving rehabilitation and efficiency upgrades (approximately in the 3-7 cents per kWh range) whereas other major redevelopment in the north could be higher. We intend to conduct further analysis to confirm hydroelectric development unit energy costs.

There are many factors and variables that can impact on the development and timing of new or upgraded hydroelectric plants in Ontario, including economics, site location, active participation of First Nations, transmission connectivity including integration with the overall transmission plan, environmental issues and Environmental Assessment (EA) approvals. For planning purposes and as input to the IPSP, we have developed a generic development timeline assuming a representative small hydroelectric project (10 MW or less) on a greenfield site located on Crown land. The corresponding timeline for redevelopment at an existing site is likely somewhat shorter.

The timeline covers four typical phases of such a project and is based on an empirical review of recent or current projects across the province as well as in consultation with developers and consultants:

Pre-feasibility (12-15 months): This phase typically includes activities aimed at developing a preliminary business case and includes, for example, site data gathering and analysis, preliminary design and economic analysis, initiation of regulatory processes and interaction with stakeholders or interested parties and financing. Successful completion of the pre-feasibility phase may culminate with the proponent making an application to the Ministry of Natural Resources (MNR) expressing interest to develop the site and being designated as the Applicant of Record (AoR).

Feasibility (15 months or longer): The feasibility phase can potentially be the longest of the four project phases, with the biggest variable being the EA process and obtaining the requisite EA approval. Other activities typically include detailed engineering design, engagement of consultants, contractors and prospective suppliers, finalization of the business plan and securing of financing.

Design and Construction (24 months or longer): Depending on the complexity of the project and barring unforeseen circumstances, the design and construction phase is relatively straightforward. However, the nominal 24 month duration can be longer depending on site issues, quality of the design, EA requirements, supplier and contractor interfaces, construction resource availability as well as connectivity to the electrical grid. Successful completion of the design and construction phase typically also involves the granting of a waterpower lease to the proponent by the government.

Commissioning and In-service (two months): To a large extent, the commissioning and in-service phase depends on how well the preceding phases were carried out in order to minimize surprises and unforeseen problems and to allow orderly and fast progression to project in-service.

3.1.3 Considerations for Hydroelectric Potential

The sites identified in the Future Potential category (see Table 3.3) represent valuable, renewable and sustainable resources that warrant further attention if the development of their potential is to be realized. In order to facilitate their development, it is worthwhile to identify a number of key factors that uniquely affect them:

- remote, and typically, northern Ontario site locations
- availability of transmission and integration with the transmission plan
- active participation of First Nations
- environmental issues and EA process requirements
- applicable governmental commitments and policies
- extent and reliability of existing site knowledge base.

With respect to the sites identified in the Future Potential (Constrained) category, the most important issue relates to current policy or commitments constraining their development. If those restrictions were changed, our assessment of their potential might change. However, at this time we are not assuming their availability for future development and these sites are not included as part of the proposed IPSP supply resource plan.

3.2 Hydroelectric Imports

The *Supply Mix Advice Report* recommended the inclusion of a 1,250 MW import for planning purposes. There is a reasonable expectation that one or more of several possible sources will come to fruition in the future. The following is a summary of possible major sources identified at this time:

Manitoba Hydro

There are ongoing discussions between Ontario and Manitoba Hydro on the feasibility of importing power from Manitoba's available resources. The potential sources of power from Manitoba include hydroelectric projects, such as Conawapa and Gull Island, that are under consideration by Manitoba Hydro for future development. The power generated from Manitoba's resources would be transmitted over a high voltage transmission line to be constructed as part of a related export interconnection project.

The Conawapa Generating Station would be the largest hydroelectric project ever built in northern Manitoba. It would be capable of generating 1,380 MW of electricity at a site on the Lower Nelson River, 28 kilometres downstream of the Limestone Generating Station and 90 kilometres downstream of Gillam. The Conawapa facility would require no significant water storage upstream and preliminary studies indicate the project would cause only limited flooding (approximately 5 km^2) of land beyond the natural banks of the Nelson River.

The Gull Island Generating Station is located about 30 kilometres west of Gillam and 180 kilometres east north east of Thompson with a capacity of about 600 MW and possible in-service date of 2011/2012.

The projected in-service date for the Conawapa project is 2017. Construction would take 8-8.5 years. The estimated in-service cost of the generating station is $3.4 billion, plus possibly up to $2.5 billion for the associated transmission facilities.

The generating station would be expected to create an estimated 5,400 person years of construction employment over the eight to nine year period. A large number of these job opportunities would be filled by northern residents. Qualified northern Aboriginal workers would have first preference for jobs. No final Conawapa development, design or construction decisions have been made to date. Routes of construction power lines, collector lines, long distance HVDC (high-voltage direct current) lines, and the location of converter stations have not been determined at this time although preliminary studies have identified several feasible options.

The large size of the Conawapa development with respect to the Manitoba Hydro load makes it highly desirable for Manitoba to couple its development with a large export for some period after the generation is developed. Manitoba has substantial interconnections to the U.S. market south of it, but the extent of the U.S. interest in this possible supply is unknown.

The existing interconnection with Manitoba is too small in scale to be reinforced sufficiently to accommodate large imports. Hence, a critical enabling requirement for large imports of hydroelectric power from Manitoba is the need for major new transmission in Ontario to deliver the power to the Ontario market. There are a number of possible schemes under consideration, but these are also affected by many other issues such as the need to incorporate wind power and water power resources that may be developed in northern Ontario over the 20-year timeframe, supply for aboriginal communities and other northern Ontario loads, and a variety of complex issues related to environmental sustainability, and cost and benefits to communities along the development corridors.

Hydro-Quebec

As noted in Hydro-Quebec's Strategic Plan 2006-2010: *Hydro-Quebec Renews its Commitment to Sustainable Development*, Hydro-Quebec TransEnergie plans to invest $5 billion in this timeframe. Among these investments, Hydro-Quebec TransEnergie has indicated that it will build a new 1,250 MW tie with Ontario near Ottawa in the near future. It will be an important addition to Ontario's existing interconnections, facilitating faster, more reliable and larger interchanges between the two provinces.

Included in the Strategic Plan, Hydro-Quebec announced that it plans several major hydroelectric power developments in the province, both to serve its own load and to provide power for sale to the export markets that surround it. Depending upon the ability of Hydro-Quebec to make progress on these developments, and the relative competitiveness of the Ontario market with those in other jurisdictions surrounding Quebec, there could be sizable amounts of energy available for Ontario. The completion of the aforementioned 1,250 MW tie would facilitate imports from Quebec.

Newfoundland and Labrador Hydro

Newfoundland and Labrador Hydro plans to develop two major generating stations (Muskrat Falls – 824 MW, and Gull Island – 2,000 MW) on the Lower Churchill River in Labrador, with much of the resulting output being delivered to Quebec and Ontario.

Newfoundland has recently announced that it will proceed independently to develop these generating resources. It is unclear, at present, how this power may be delivered to Ontario or other markets as Hydro-Quebec has announced plans to develop large new generating facilities near the border with Labrador which may fully utilize the existing Quebec transmission. The need to build new transmission to incorporate the Lower Churchill developments could result in delays and challenge both the viability and timing of the developments. Newfoundland and Labrador Hydro has requested transmission rights to have the power delivered through to Ontario, but the outcome of the request is unknown at present.

In summary, we consider it a reasonable assumption that 1,250 MW of hydroelectric imports from Quebec may materialize in the near term. For additional hydroelectric imports from Manitoba or Newfoundland and Labrador, there appear to be significant barriers at present related to approvals, cost, and transmission siting considerations. Likely in-service dates for these long distance imports are in the post-2015 to 2025 timeframe.

3.3 Non-Hydroelectric Imports

While not explicitly considered in this paper, the potential also exists in the future for the import of electricity generated by non-hydroelectric resources, e.g., from New York. To the extent that such opportunities become available in the future, we intend to assess their viability and value to the IPSP.

3.4 Wind Power

Recent Information and Analysis

OPA has further refined its estimates made in the supply mix advice exercise regarding the potential for wind generation in Ontario and its implications. In addition to the work completed in 2005, OPA has completed several studies and evaluations of wind resources in Ontario.

Hélimax Energy Inc. (Hélimax)[3] was commissioned to undertake a study to:

- project or anticipate the locations of future large-scale wind energy development within the province south of the 50th parallel
- rank the sites based on their viability, assuming equal electrical grid integration conditions at all sites, and calculate the potential capacity (MW) that each site can accommodate
- calculate approximate energy production (GWh) at each of the projected sites
- provide a generic schedule for the development of a wind power project from initial project conception to project commissioning, and
- provide preliminary estimates for construction, operation and maintenance costs of developing a generic wind site in Ontario.

The Hélimax study focuses on the development of large wind farms. Consideration of smaller scale wind generation (under 10 MW) at customer sites for their own use is described in Section 5 "Promising Technologies and their Potential." This section also includes a discussion of how the Standard Offer Program is intended to foster development of smaller scale wind power. The sites for large-scale development of wind power (namely, facilities directly connected to the provincial grid) identified in this study have been chosen based on a number of specific site selection criteria and ranking methodology as shown in Figure 3.3.

Once all the constraints are identified, an analysis map of the province is created. This map is the basis of the site selection process. Project locations are selected for areas that could reasonably accommodate a significant quantity of wind energy. Areas of highly fragmented wind resource or areas considered unable to accommodate at least 50 MW are discarded from the analysis. No consideration is given to the sites' proximity to the electrical grid and particular attention is paid to select geographically dispersed sites below the 50th parallel.

[3] The web links to access these studies are http://www.ieso.ca/imoweb/pubs/marketreports/OPA-Report-200610-1.pdf http://www.powerauthority.on.ca/Storage/15/1110_Part_4.6_Helimax_Report_on_Wind_to_OPA_-_2005.11.24.pdf

Figure 3.3 – Site Selection and Ranking Methodology for Wind Sites

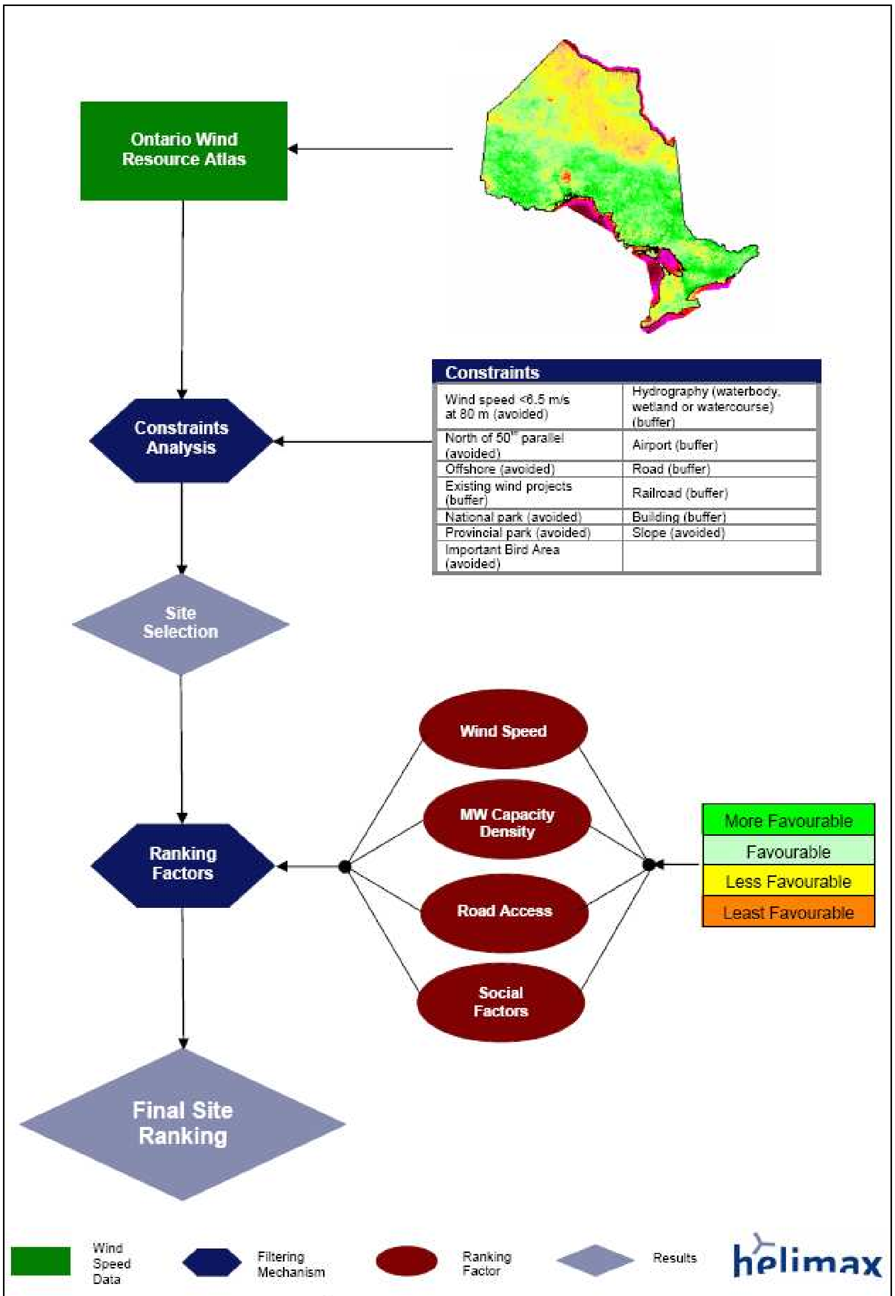


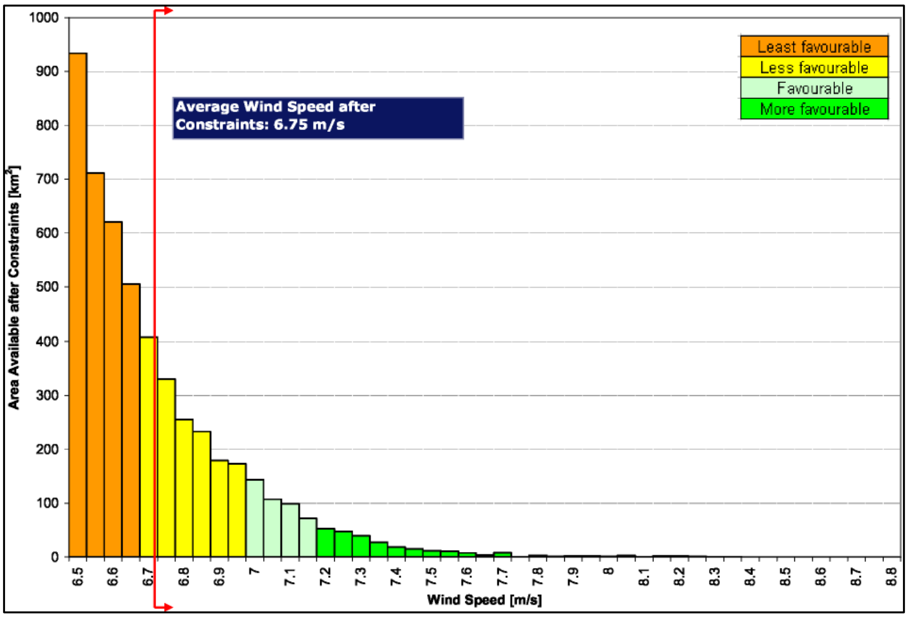
Figure 2-1: Hélimax's Site Selection and Ranking Methodology

Source: OPA, Hélimax

In all, 60 sites have been selected and ranked throughout the study area. Sites located in areas of good wind speeds, high MW/km² capacity, near road access and in areas of low population density were considered for further analysis.

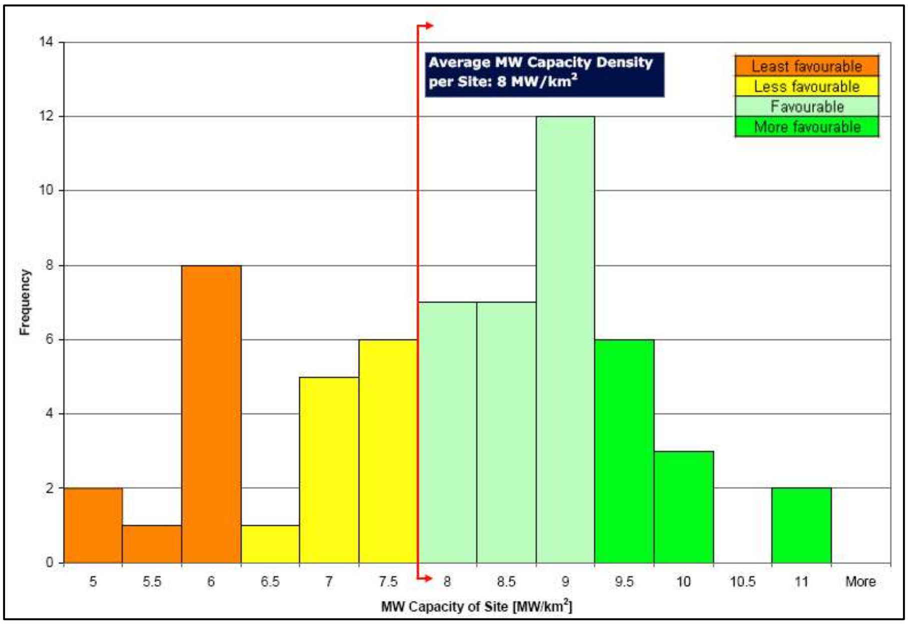
Figure 3.4 illustrates the land area available for wind development and Figure 3.5 shows the megawatt capacity density of selected sites.

Figure 3.4 – Land Area Available for Development as a Function of Wind Speed



Source: OPA, Hélimax

Figure 3.5 – Megawatt Density Profile of Selected Sites



Source: OPA, Hélimax

Table 3.5 shows the results of the energy yield estimates and net associated capacity factors for each site.

Table 3.5 – Energy Yield Estimates and Net Capacity Factors

Site ID	Potential Installable Capacity (MW)	Net Energy Yield (GWh/year)	Net Capacity Factor (%)	Site ID	Potential Installable Capacity (MW)	Net Energy Yield (GWh/year)	Net Capacity Factor (%)
1	61	175	33	31	69	182	30
2	33	98	34	32	48	127	30
3	200	541	31	33	72	183	29
4	200	539	31	34	112	276	28
5	200	530	30	35	200	493	28
6	167	436	30	36	200	500	29
7	107	282	30	37	49	127	29
8	107	281	30	38	119	295	28
9	200	534	30	39	200	497	28
10	200	526	30	40	177	456	29
11	50	137	31	41	200	491	28
12	95	248	30	42	40	97	28
13	125	317	29	43	200	490	28
14	88	226	29	44	200	489	28
15	84	216	29	45	200	496	28
16	163	427	30	46	200	494	28
17	187	470	29	47	200	486	28
18	115	288	29	48	200	490	28
19	41	112	31	49	66	162	28
20	148	377	29	50	172	404	27
21	200	529	30	51	44	107	28
22	155	395	29	52	130	331	29
23	200	510	29	53	162	411	29
24	200	522	30	54	179	430	27
25	42	111	30	55	154	373	28
26	200	522	30	56	152	378	28
27	200	523	30	57	100	246	28
28	96	243	29	58	79	193	28
29	109	294	31	59	60	145	28
30	109	278	29	60	123	291	27
			Cumulative Total		8,191	20,827	AVG: 29

Source: Hélimax

For example, a site ranked as Site 1 is classed as more favourable for the wind speed factor. This means that it has average annual wind speeds of greater than 7.2 m/s; a favourable MW capacity density indicating a capacity of between 8- 9.5 MW/km^2; it has been classed as more favourable for the road access factor, indicating that it is within 10 km of the road network; and, it has been classed as more favourable with respect to population density, indicating that it is located in a region of less than one inhabitant per square kilometre. The fact that some sites fare better than others for a given factor, but are ultimately ranked lower, reflects the weighted attribute to each factor.

Table 3.6 summarizes the factors that were considered most important or critical for wind project siting and the ranking for weighting.

Table 3.6 – Factors Used in Site Ranking Process

Factor	Description	Ranking	Weighting Method
Wind Speed	Wind speeds greater than 6.5 m/s will be considered	1	Based on data
MW capacity density	Sites with larger MW capacity density are of greater interest	2	Based on data
Road access	Distance from roads	3	Based on data
Social	Population density	4	Based on data

Source: Hélimax

3.4.1 Generic Project Development Schedule Cost Estimates

Schedule

A generic outline of a wind farm development schedule has been prepared to provide guidance for future development. The five principal activities contained in the schedule are listed chronologically in the order of their execution. The durations of activities as shown in Table 3.7 are provided as guidelines. A more detailed work plan would be drawn up by project developers prior to construction. The schedule does not take into consideration the current shortage of wind turbine generators in today's market. It assumes that interconnection to the electrical grid is not on the critical path and could be completed during construction. The schedule also assumes that the project is able to obtain suitable financing soon after its feasibility has been established during the development phase.

Table 3.7 – Time Required to Realize Wind Projects

	50 MW	100 MW	150 MW	200 MW
	Duration (months)			
Development	16	16	16	16
Design and Engineering	6	6	6	6
WTG Procurement (shipping)	12 (4)	14 (6)	16 (8)	17 (9)
Civil Works	6	8	10	11
Interconnection	6	6	6	6
WTG Erection and Commissioning	7	9	11	12
Total Project Duration	30	33	35	36

Source: OPA, Hélimax

The duration of certain activities are a function of the size of the project while some others are not. The development phase, for instance, would take the same amount of time irrespective of the project size. Table 3.7 shows the amount of time required for project related activities as a function of the megawatt capacity of the project. The numbers given are approximate and could change significantly from one project to another depending in part on the means and resources of the developer. It should be noted that the comments outlined above still remain valid.

A budget estimate for a generic 100 MW wind farm has also been developed as shown in Table 3.8. The estimates have been calculated for a generic project at an average location (i.e., typical meteorological conditions, constraints and development costs) in Ontario. Significant deviations from these estimates can be expected, as actual figures will greatly depend on site conditions during construction and operation.

Table 3.8 – Project Budget for a Generic 100 MW Wind Project

		Cost (K$ Cdn) (Feb 2006 dollars)	Proportion of Budget (percent)
1	Design Engineering – Project Management	3,700	1.8
2	Hard Costs	170,875	84.6
2.1	Wind turbine (complete): erection, transportation	152,275	75.4
2.2	Civil works (access roads, trenches, foundations, substation)	9,110	4.5
2.3	Wind turbine equipment and cables (cubicles, switchgears)	6,000	3.0
2.4	Interconnection (substation, overhead line, communication)	2,590	1.3
2.5	Controls (SCADA, anemometry)	490	0.2
2.6	Miscellaneous costs (initial spares, aerial safety lighting, training)	410	0.2
3	Soft Costs	7,410	3.7
3.1	Development costs (wind resource assessment, permitting and other preliminary engineering)	2,780	1.4
3.2	Legal and other fees (land lease, other contracts, testing and other consultancy)	1,850	0.9
3.3	Financing (brokerage, currency exchange risk, interest during construction, management)*	2,780	1.4
4	Project Contingencies **	20,000	9.9
Total Project Budget		201,985	100.0

Notes: The table above depicts the total project construction budget which amounts to approximately C$202 million (2006 dollars).
* Will vary significantly depending on financing structure.
** To cover significant fluctuations in WTG price and site conditions.
Source: OPA, Helimax

The project budget includes among other items the cost of the wind turbines delivered and installed on site as well as the commissioning. These costs have been adapted to the Ontario generic case based on Hélimax's knowledge and experience and will vary depending on specific site conditions and complexity.

Wind Project Cost Estimates

Estimates for project costs and O&M costs are given for various installed capacities. These figures should be taken as indicative estimates only, as actual budgets will be based on several factors that might significantly affect the final installed or O&M costs. Four additional scenarios, 20 MW, 50 MW, 150 MW and 200 MW projects, are given to illustrate the variation of costs relative to the base case 100 MW project. As can be seen in the 20 MW project example, lower installed capacity projects are more sensitive to specific conditions and as such will display a non-linear variation trend of the costs compared to larger-scale projects. Table 3.9 below gives the costs per kW of installed capacity for the total project (installed) cost estimate and the cost per kWh for the O&M costs estimate.

Table 3.9 – Wind Project Costs versus Capacity

Wind Farm Capacity (MW)	Installed Cost ($/kW)	O&M Costs (Cents/kWh)
20	2,424	2.20
50	2,121	2.00
100	2,020	1.88
150	1,979	1.81
200	1,959	1.76

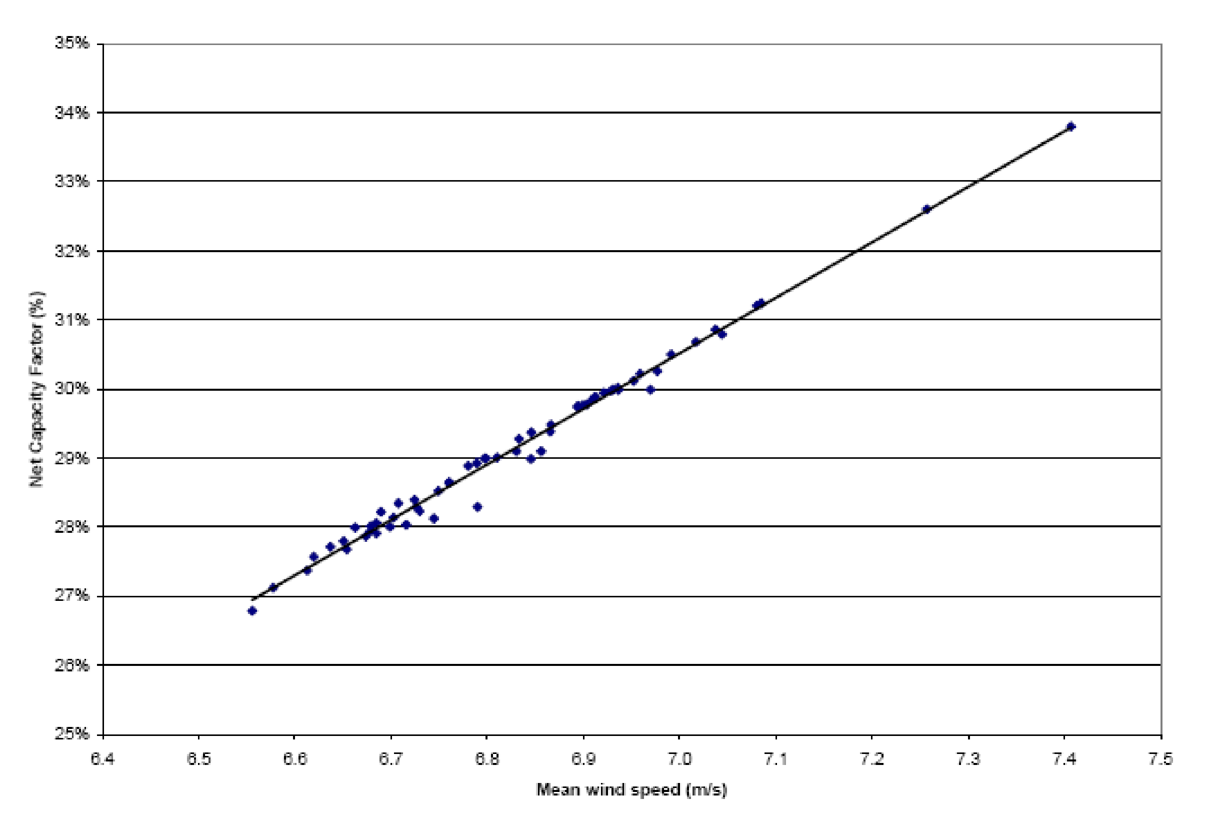
Source: Hélimax

Figure 3.6 shows the correlation between the average net capacity factor and mean wind speed for each site. The net average annual output divided by the maximum output at rated capacity ranges from 27 percent to 34 percent. The average net capacity factor for all sites is approximately 29 percent. These values may be of assistance to developers for prospecting and ranking purposes.

Table 3.10 shows the data collected from individual stations and the output is aggregated for a group of sites. In addition to the projects which are signed under RFP (Request for Proposals) contracts, the combined capacities and estimated net annual generation for each of the 10 regional groupings is shown, indicating a range from 143 MW to 1,752 MW. For Ontario, a total generation capacity of 8,727 MW with an estimated generation potential of 21 TWh is identified.

Figure 3.7 shows the location of the groups of potential wind sites summarized in Table 3.10.

Figure 3.6 – Correlation of Capacity as a Function of Wind Speed



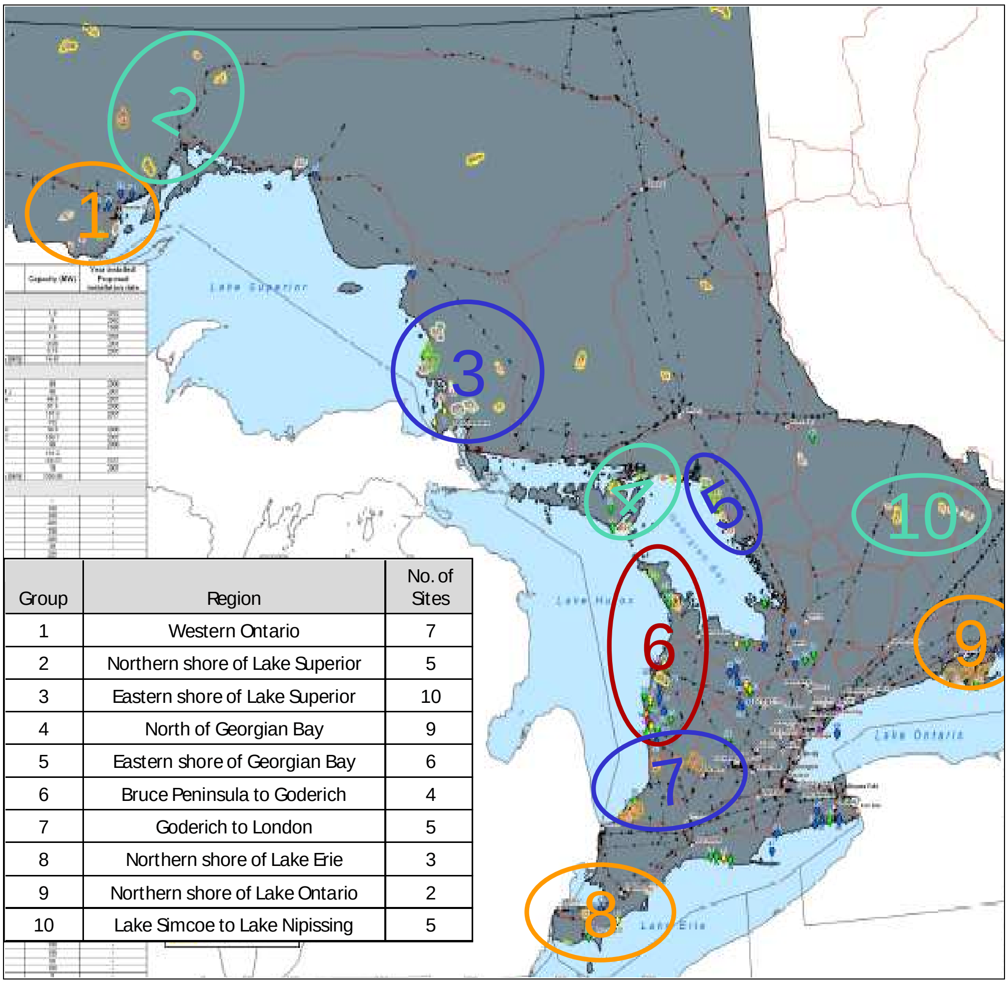
Source: Hélimax

Table 3.10 – Wind Resource Data Aggregated by Regions

Group	Region	No. of Sites	MW Capacity	Annual Generation GWh	Hélimax Generation GWh
1	Western Ontario	7	827	2,044	2,101
2	Northern shore of Lake Superior	5	783	1,817	1,931
3	Eastern shore of Lake Superior	10	1,752	4,303	4,542
4	North of Georgian Bay	9	1,267	2,985	3,189
5	Eastern shore of Georgian Bay	6	773	2,004	2,051
6	Bruce Peninsula to Goderich	4	617	1,498	1,577
7	Goderich to London	5	514	1,163	1,253
8	Northern shore of Lake Erie	3	143	364	392
9	Northern shore of Lake Ontario	2	292	698	742
10	Lake Simcoe to Lake Nipissing	5	449	1,094	1,165
Signed		12	1,312	3,388	NA
Total		68	8,727	21,358	

Source: AWS Truewind

Figure 3.7 – Location of Potential Wind Sites



Group	Region	No. of Sites
1	Western Ontario	7
2	Northern shore of Lake Superior	5
3	Eastern shore of Lake Superior	10
4	North of Georgian Bay	9
5	Eastern shore of Georgian Bay	6
6	Bruce Peninsula to Goderich	4
7	Goderich to London	5
8	Northern shore of Lake Erie	3
9	Northern shore of Lake Ontario	2
10	Lake Simcoe to Lake Nipissing	5

Source: GE Ontario Wind Integration Study

Wind Integration and Implications for Grid Operation

A study was performed by General Electric (GE) to assess the implications of large-scale wind penetration into the Ontario power system. The study was undertaken on behalf of the OPA, the Canadian Wind Energy Association (CanWEA) and the IESO.[4]

Study results were used to assess the time-varying behaviour of wind generation in a realistic manner, taking into account existing and planned wind projects and likely areas for future development. In order to do this, it was necessary to produce data spanning at least one continuous year to allow an assessment of the impacts of wind on the electricity system in every season. This has been accomplished using wind data collected by project developers at numerous sites in the province. The sites cover most of the areas under active development. The

[4] The GE study entitled "*Ontario Wind Integration Study*" October 2005, is posted on the IPSP website: http://www.powerauthority.on.ca/ipsp/.

end result is a set of data files containing a complete year of 10-minute wind speed, direction, and temperature for each of the 31 monitoring stations that forms the basis for estimation of the 10-minute wind plant output.

In order to preserve data confidentiality, the data are aggregated for 10 groups of new projects with combined rated capacities ranging from 143 MW to 1,792 MW. The groups correspond to broad geographic areas, and are numbered starting from extreme western Ontario, across the northern shore of Lake Superior, and then south towards Lake Erie as shown in Figure 3.7. The regional aggregated data for the groups are listed in Table 3.10 along with their rated capacities and estimated net annual generation.

Most of the project sites under development today are located in or near groups 1, 2, 3, 6, 7, 8, and 9. Combined, these groups represent 4,928 MW.

Energy production profiles are developed for each group of wind generator sites across the province, in order to assess the operational impacts of integrating up to 10,000 MW of wind power into Ontario's electricity system. This includes determining the expected monthly wind power output during weekday peak hours, and determining the maximum amount of wind power that could be added to the Ontario system with minimal impact on system operation.

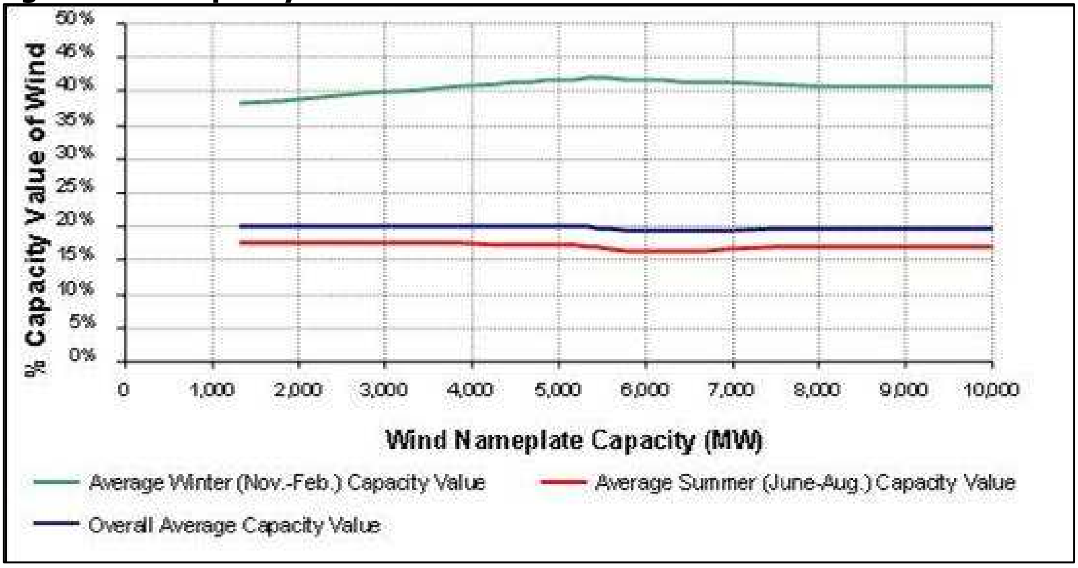
Wind Integration: Key Conclusions

The GE wind integration study provides several important early conclusions regarding capacity value and operational impacts of large-scale wind power generation in Ontario. A wide range of wind levels were selected to help identify the incremental impact of wind on the Ontario power system.

Capacity Value

The average capacity value of the wind resource in Ontario during the summer (peak load) months (for the 12 months considered) is estimated to be approximately 17 percent. The capacity value ranges from 38 percent to 42 percent during the winter months (November to February) and from 16 percent to 19 percent during the summer months (June to August). Capacity values are based on an analysis of those periods when the hourly demand was within 10 percent of the annual peak. Since 87 percent of the periods within 10 percent of the load peak occur during the summer months, the overall yearly capacity value is expected to be heavily weighted toward the summer. The overall capacity value for the 12 month study period is approximately 20 percent for all wind penetration scenarios. As shown in Figure 3.8, the capacity value is generally insensitive to the wind penetration level, mainly due to good wind geographic diversity and the fact that the various wind output levels are derived by scaling the same wind groups.

Figure 3.8 – Capacity Value of Wind versus Wind Penetration

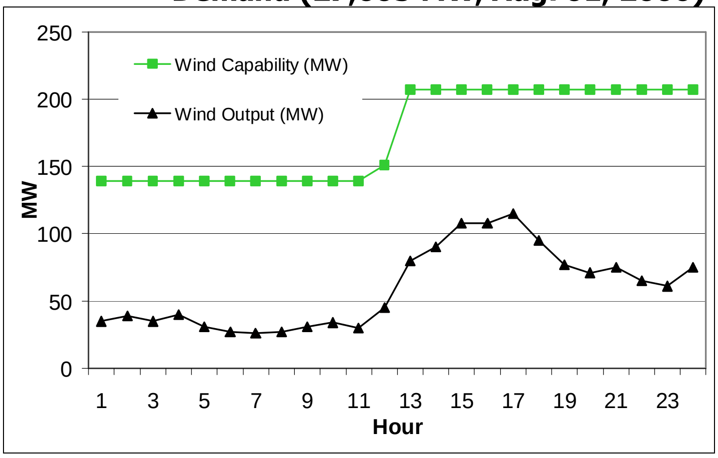


Source: GE Ontario Wind Integration Study

As a point of comparison, Figure 3.9 shows the wind output in relation to the installed wind capability during Ontario's all-time peak demand day on August 01, 2006.

Although the amount of installed wind capacity was relatively small, close to 50 percent of that capacity was available during hour 16, the peak hour. This illustrates the value of actual operational data. Based on ground-level wind data, there is clearly great variability from year to year at the time of summer peak. As more historical wind data become available, we will be better able to forecast the capacity contribution of wind. In addition, we will continue to assess various forecasting methodologies in order to improve wind capacity forecasts.

Figure 3.9 – Wind Contribution to Ontario Peak Demand (27,005 MW, Aug. 01, 2006)



Source: IESO

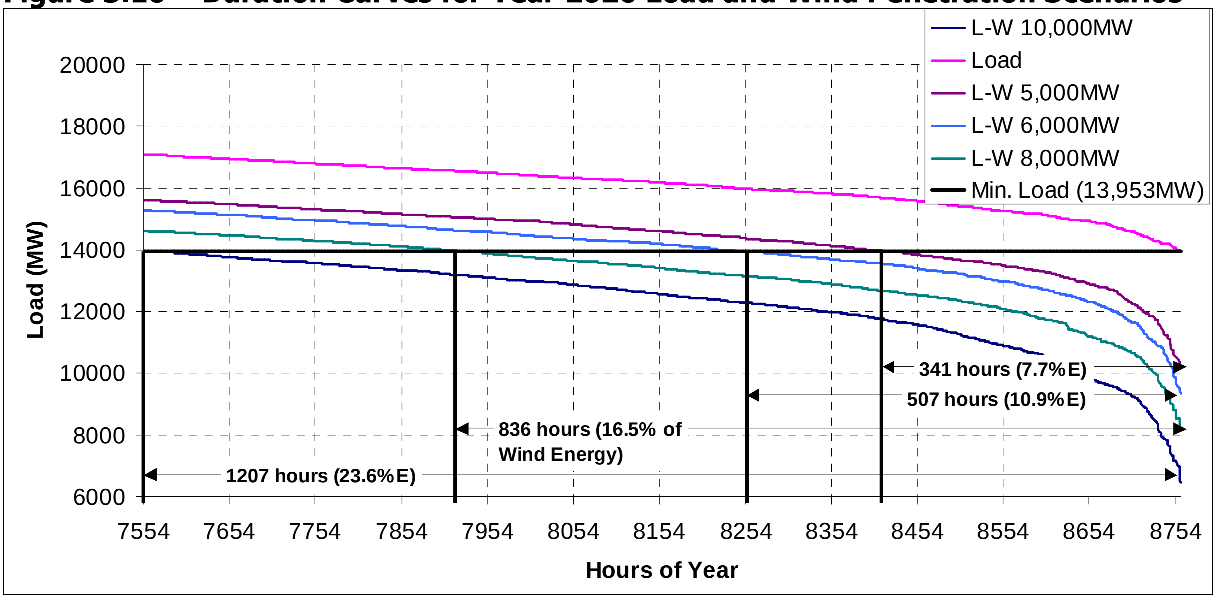
Low Load Period Considerations

The GE study also focused on the impact of increased wind penetration on overall system operability. This is particularly critical during light load periods when the load is near its minimum and the wind production is quite high (such as early mornings during shoulder months). During such periods, the net "load-minus-wind" level during the period could be up to 50 percent lower than the load-alone minimum point. In other words, the wind pushes the net load point lower than it ordinarily would be.

This is illustrated in Figure 3.10 which shows load and "load-minus-wind" duration curves for 2020 for various levels of wind penetration. The minimum load point (13,953 MW) is represented by the heavy horizontal line. The figure shows the number hours that net-load (for each scenario) dips below 13,953 MW, as well as the percent of wind energy below the minimum load line. For 10,000 MW of wind, the net-load drops to less than 7,000 MW, which is 50 percent less than the minimum load point for load-alone (13,953 MW).

If the supply mix during these low load periods does not have adequate ramping capability to adjust for the wind variability, the secure, stable operation of the power system could be compromised. If the minimum load minus wind drops far enough down into the generation stack, then only less maneuverable generation units may be left to serve load.

Figure 3.10 – Duration Curves for Year 2020 Load and Wind Penetration Scenarios



Source: GE Ontario Wind Integration Study

There are several potential measures that can be taken to mitigate the low load-wind issue such as (i) shed wind or use wind farm controls to provide flexibility; (ii) modify the load by adding loads during low load-wind periods (e.g., pumped storage), (iii) export wind to other systems or (iv) use a flexible generation mix during low load periods.

Grid Operational Considerations

Additional key conclusions from the GE integration study are as follows:

- The results of the regulation analysis show that, in all scenarios, the incremental regulation needed to maintain current operational performance is small. This additional regulation could be handled within the current system operation framework.
- Incremental load-following requirements are more substantial due to increased variability in the five-minute timeframe. The "2009 Load with 1,310 MW" of wind scenario could be easily accommodated with the existing generators. The "2020 Load with 5,000 MW" of wind scenario shows a 17 percent increase in load-following requirements. It is likely that existing generators could provide this incremental requirement. However, as the supply mix changes over time, it will be important to ensure that this load-following capability is maintained. Beyond 5,000 MW of wind, the additional loads following requirements exceed the capability of existing generators.
- The 10-minute variability was analyzed as a proxy for operating reserve requirements. Below 5,000 MW of wind, the incremental operating reserve requirement is considered negligible. Above 5,000 MW of wind, the incremental operating reserve requirement becomes more significant, and at 10,000 MW of wind, operating reserve considerations become very important.
- For all wind scenarios, the hourly and multi-hourly incremental variability due to wind is small and not considered a major operational hurdle. Future improvements in short-term wind forecasting will help to confirm whether this is the case.
- The analysis shows that sudden (less than 10-minute) province-wide interruptions of wind generation power output are extremely unlikely and do not represent a credible planning contingency.
- When large changes in wind output do occur on a site or group basis, spatial diversity ensures that the impact on aggregate wind output is mitigated to a large extent.

As Ontario relies increasingly on these intermittent resources, there will be an increasing need for system reserves that can be called upon at times of high demand in the event the intermittent resource is not available. A combination of energy storage, load management or load creation through the use of promising technologies would be necessary to capture the economic value of wind generation during low load-wind periods. Some of these promising technologies are described further in Section 5.

Wind Resource Costs

We are performing analyses to examine the financial implications of accommodating a large amount of wind power in Ontario. To provide a comprehensive and integrated view of the role that the wind resources can play in the future, we are developing the "all-in" unit costs of wind energy levelized over the operating lifetime of turbines. These costs include the associated connection and bulk transmission facilities as well as the additional incremental reserve capacity required to account for variability in wind power production. "All-in" costs are discussed further in the Integration paper (discussion paper #7).

In order to simulate the cost of new wind farms, 60 hypothetical sites have been taken from the Hélimax study (see section 3.3) as well as 14 actual sites currently being proposed, but not yet signed. Only sites with an anticipated capacity of over 20 MW are used, since smaller sites are less likely to adversely affect the grid. In total, this leaves 74 sites.

The potential capacity of these "placeholder" wind farms was provided by Hélimax. The annual capacity factors for these sites were determined using data provided by GE. Since the GE data had been amalgamated on a region-by-region basis, any site falling in a specific area is assigned the same capacity factor as its immediate neighbouring sites.

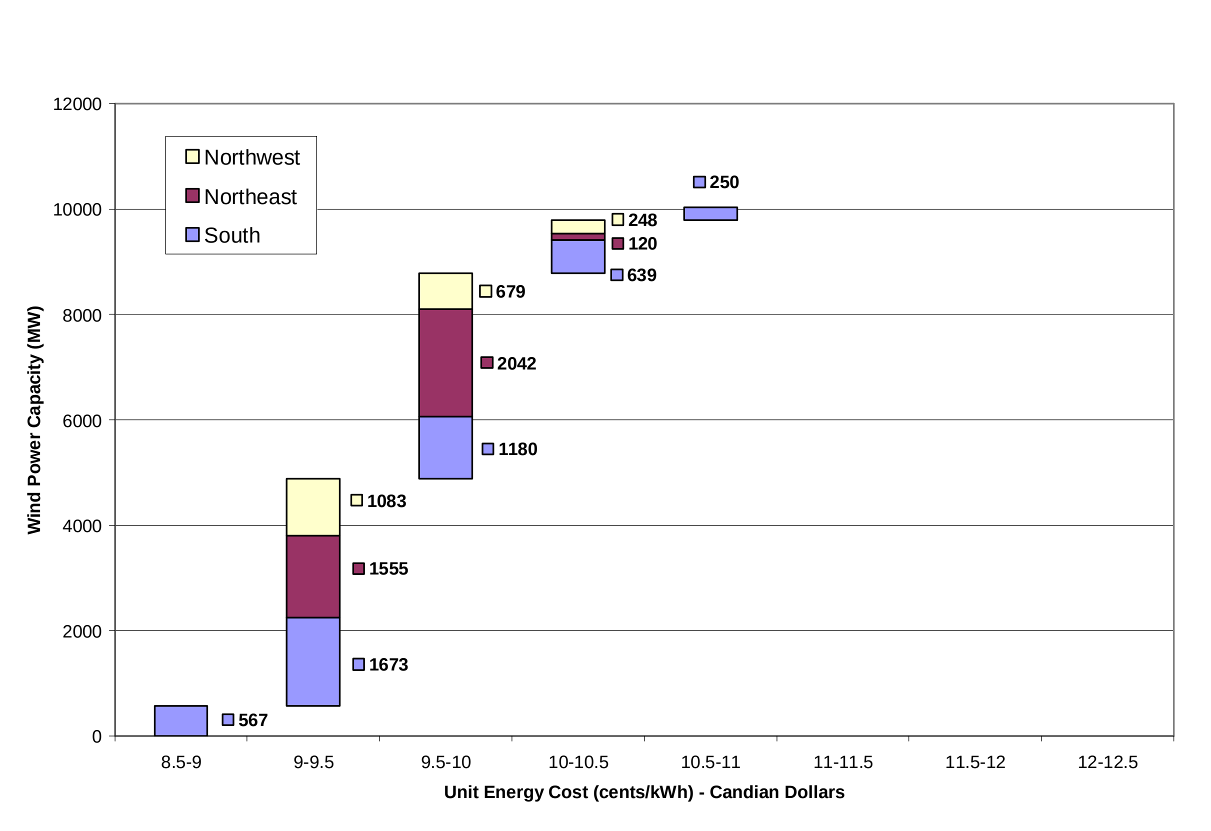
Generic project development schedules and project cost estimates for various installed capacities, in Table 3.7, Table 3.8 and Table 3.9, should be considered as indicative estimates.

For the study, a unit energy cost is calculated for each potential wind farm. This is done by taking the capital cost for the site, interpolated from Table 3.9 as needed, and annuitizing it over the wind farm's life. The annuity is then divided by the expected annual energy production from that site. To this unit energy cost is added the unit OM&A, again interpolated from the above table as required. The result is the unit energy cost (often referred to as the levelized unit energy cost (LUEC)). The costs vary between 8.89 and 11.72 cents/kWh.

For the purposes of this analysis, the lifetime of a wind farm is assumed to be 20 years, and the discount rate is set at 7 percent. It should be noted that final costs proved to be very sensitive to discount rate, with the most cost-effective site (before interregional upgrades) at 9.72 cents/kWh with a discount rate of 7 percent, and 8.54 cents/kWh when the discount rate is reduced to 5 percent. However, since all sites are assessed on the basis of the same discount rate, the ranking of sites remained unaffected.

Figure 3.11 shows wind power unit energy costs by particular regions of Ontario. Availability of substantial wind generation capacity, approximately 9,000 MW, is indicated in the 8.5-10 cents/kWh range.

Figure 3.11 – Wind Resource Unit Costs (Energy Production)



Note: LUEC excludes connection and interregional transmission upgrade costs.
Source: OPA

Cost of Connection

The costs associated with delivering wind energy to customers comprise the cost of transmission facilities required to connect the wind resource to the transmission grid (connection cost), the cost of any transmission upgrade required along affected delivery paths to minimize congestion (bulk transmission cost) and the delivery efficiency as measured by percentage of losses as a function of energy generated by the wind resource.

The connection facilities required for each wind resource are determined by the location of the wind resource, its proximity to the transmission grid, and its generating capacity. Where possible, a group of developments in an area will be considered together to minimize the number of lines required and the overall cost, and to avoid other constraints. Depending on the capacity required, the length of the connection and the characteristics of the transmission grid being connected to, voltages of either 115 kV or 230 kV are used for the connection facilities. For developments of significant magnitude, i.e. 1,000 MW or more, 500 kV connections may be also considered.

A set of unit cost estimates for transmission lines used in estimating the connection cost of wind generation facilities are shown in Table 3.11. The costs for all 230 kV and 500 kV lines are based on the use of lattice towers, while the costs for 115 kV lines are based on the use of wood poles. The costs also include land procurement surcharges of 10 percent in northern Ontario and 15 percent in southern Ontario.

Table 3.11 – Cost of Transmission Lines for Estimating Connection Costs ($M/km)

Region	Single 115 kV	Double 115 kV	Single 230 kV	Double 230 kV	Single 500 kV	Double 500 kV
Northern	0.330	0.426	0.770	0.880	0.990	1.788
Sourthern	0.288	0.388	1.006	1.222	1.323	1.653
Line Limit	150 MW	300 MW	400 MW	800 MW	--	--

Source: OPA

Table 3.11 also shows the power transfer capabilities for 115 and 230 kV lines. They are based on thermal loading limits of typical lines of these voltage classes. Capabilities for 500 kV lines are not provided as stability and voltage performance, rather than thermal loading, are the dictating factors. For the purpose of planning wind connection, a single 500 kV circuit is assumed to have a capability of over 1,500 MW.

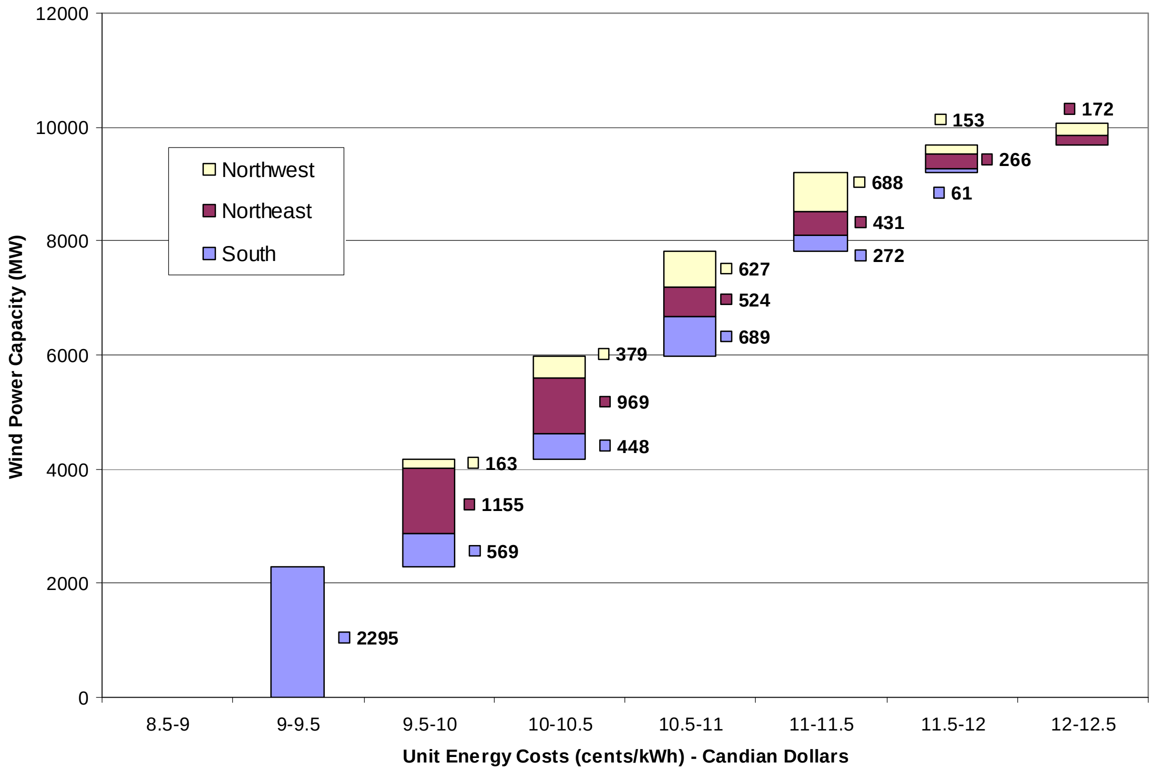
"Enabler" lines, which are discussed in more detail in the Transmission paper (discussion paper #5), are connection lines built to facilitate the development of large renewable resource potential in locations remote to the transmission grid. The costs of these lines and the short connecting line from the development locations to the "enabler" line are included as part of the connection cost for the different wind generation developments. Station costs have not been included in the connection costs. They are assumed to be included in the wind generation project costs.

For sites sharing a primary connection line, the cost of this connection line would be allocated to the developments in proportion to their capacities and their connection distances.

In addition to the connection costs, there are losses in delivering the wind generation to the loads and they are location specific. Transmission losses were studied using power flows simulating transfers from different locations in Ontario to the load centre in the GTA. The results from these studies are expressed as a percentage of energy not delivered to the customer from the total energy production for each wind generator.

Figure 3.12 shows the LUEC including energy costs, connection costs and the impact of transmission losses for the potential wind development sites in Ontario. Note that these costs do not include bulk transmission upgrade costs. Those upgrades are not related to only wind developments and require a broader consideration of other resource developments in the regions.

Figure 3.12 – Wind Resource Unit Costs (Including Connection Costs and Losses)



Source: OPA

The revised LUECs show a range between 9 to 12.5 cents/kWh. In general, wind resources in southern Ontario are more economic than those in northern Ontario when connection costs and losses are considered.

3.5 Bioenergy and Municipal Solid Waste (MSW)

Recent Information and Analysis

OPA is investigating the potential for biomass to contribute to the 15,700 MW renewables target prescribed in the Minister of Energy's June 13th, 2006 directive. OPA received feedback in response to the *Supply Mix Advice Report* indicating that biomass resources have more potential to supply electricity to Ontario than the 500 MW that was assumed in the supply mix advice. The 500 MW of biomass capacity in the supply mix advice was intended as a planning assumption only, thus it does not represent a target or limitation on future potential for grid-based bioenergy.

Many challenges are associated with planning to increase Ontario's capacity to generate electricity using biomass fuels. Some of these challenges are related to the distributed nature of biomass resources, the technologies for conversion to electricity and intermediate energy carriers, and integration of biomass-derived energy to the power grid. The types of biomass vary considerably in quantity, quality and location. The conversion technologies are expensive, small in scale, and largely unproven in the Ontario context. The challenge of integrating these resources includes technical, economic, social and regulatory issues. In consulting with industries, agriculture and natural resources ministries, project developers, and other interested parties, OPA has begun to understand these challenges in addition to gaining an appreciation for the significant opportunities that bioenergy resources present for Ontario. These challenges and opportunities are discussed in the sections that follow.

Biomass Resources

Biomass can be thought of as solar energy stored in the bodies of plants by photosynthetic activity, or in the bodies and wastes produced by animals. The term encompasses a broad range of materials, including agricultural products, by-products, wood from forests, animal manure and the organic fraction of municipal solid waste. Biomass contains stored energy that could be converted to electricity by thermal processes. Of all the biomass resources that are technically available within Ontario, only some are feasible for use as biomass fuels because their use is constrained by many factors that include:

- financial viability of biomass energy projects compared to the cost of other renewable resources
- issues related to fuel collection, transport and processing
- environmental issues related to removing organic matter from forest and agriculture lands
- regulatory issues related to permits and classifications of waste materials.

These issues represent only some examples of constraints that have already been identified.

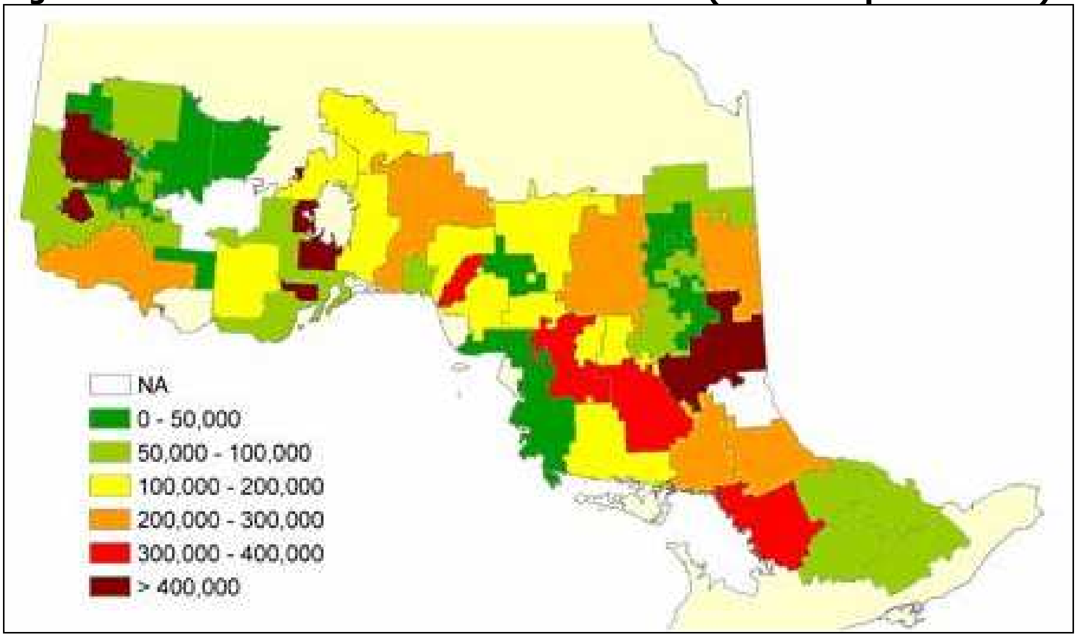
A summary of biomass sources is presented below.

Forestry and Related Industries: Ontario’s forests contain the most plant-based biomass in Ontario. This category includes tree harvest residues (“slash”), residues from silviculture practices, diseased and damaged trees, unharvested portions of annual allowable cuts, wood wastes from secondary industries, and potentially, dedicated tree plantations.

Knowledge of issues associated with the economic feasibility and environmental implications of collection and delivery of forest biomass is limited. Equipment designed to collect and bundle forest floor slash is available, and a pilot project to convert forest wood into a fuel gas or oil (“bio-liquids”) using pyrolysis is underway. Competition for the use of these liquid fuels is anticipated to divert some from power production to other end uses including transport fuels, polymers and chemical products. Processes are also being developed to convert forest biomass into ethanol, although the research to confirm the overall viability of this concept is not complete.

Figure 3.13 displays the forest management units in northern Ontario as an illustrative example of ongoing work to estimate quantities and locations of forest biomass. The Biomass Spatial Analysis Tool (BSAT), developed by the Ministry of Natural Resources with partners, employs spatial analysis to track and document excess forest biomass inventories. This model is in the early stages of development and it is hoped that this and similar tools will be able to provide prospective biomass energy developers enough information to plan, design and operate successful and cost-effective energy projects. The figure below presents data from the 2003 harvest. It is important to note that this is a snapshot in time, and that the forest management units containing excess biomass can vary considerably year to year.

Figure 3.13 – Excess Biomass Forest Inventories (BSAT Sample for 2003)



1. Blocks correspond to forest management units.
2. Colour coded categories represent the theoretical residual forest biomass in m^3, from 2003 harvest data.
3. Chart displays preliminary results from BSAT project; theoretical biomass concentrations require extensive verification work to increase confidence in the data for planning purposes.

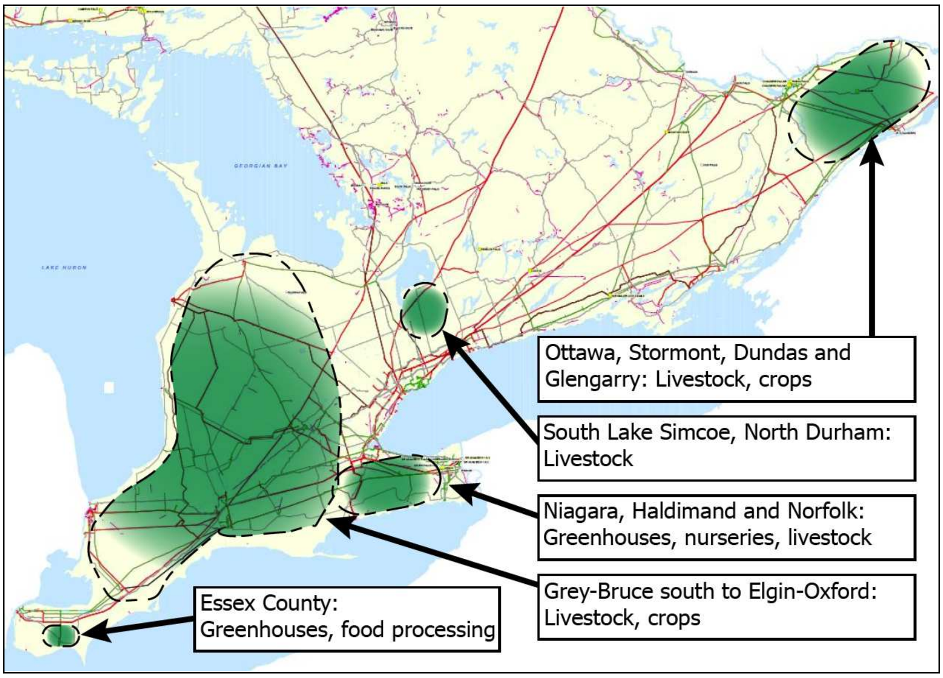
Source: Ministry of Natural Resources

In addition to forest biomass, northern Ontario has large deposits of peat, which is partially decomposed plant material that is saturated with water. When dried, peat can be burned to provide heating value similar to that of lignite coal. The water naturally present in peat is a technical obstacle to its use as a fuel, as the weight of the water makes it too expensive to transport to generator or drying location. Much of this water is embedded within the cellular matrix of the peat, and therefore it cannot be easily drained or squeezed out. Consideration is being given to burning peat at the Atikokan generating station in northwest Ontario, but further work needs to be completed before the feasibility of this option is known.

Agriculture Products and By-products: Ontario's agriculture and agri-food sectors could possibly have the second largest energy production potential behind forestry. Much of this potential is dependant upon the use of dedicated crops grown for energy, but the energy in residual and waste products can also be utilized to generate power. Some of these products include spoiled or off-specification agricultural and food products, animal manure and grain handling dust among others. Similar to forestry biomass, there is also interest in producing a fuel gas or oil from agriculture-based products rather than electricity. In many jurisdictions agricultural material is being converted to ethanol to reduce emissions from transportation and to increase domestic energy security.

Agricultural sources are located primarily in Ontario's south, with some potential sources near Thunder Bay and in northern Ontario using prairie-imported biomass. Figure 3.14 indicates some areas of agricultural production concentrated in southern Ontario according to agriculture production statistics (Ministry of Agriculture, Food and Rural Affairs, 2001; Statistics Canada, 2001). Much work is required to develop a better understanding of the quantities, qualities and locations of agriculture biomass resources in southern Ontario.

Figure 3.14 – Concentrations of Agricultural Activity in Southern Ontario



Source: OPA, OMAFRA, 2001, Statistics Canada, 2001-2004.

Municipal Sources: Sources of biomass available from the municipal sector include municipal solid waste (MSW), fats, oils and greases from food services industries (FOGs), and biosolids from wastewater treatment facilities. For all these sources, electricity production is potentially a beneficial by-product rather than being the primary driver for managing the particular biomass source.

MSW is attracting attention because many municipal landfills are near the end of their operating lives. At the same time, locating new landfill sites is increasingly challenging. A typical landfill produces methane as the organic fraction of the MSW decomposes under anaerobic conditions created by the seal of landfill cover. Methane's potency as a greenhouse gas is a driver behind the collection of landfill gases, which can be converted into useful energy.

Management of MSW with energy production as a beneficial by-product may be an alternative to creating new landfills in some municipalities. A number of MSW incineration proposals in southern Ontario are undergoing environmental assessments. Other forms of thermal treatment, such as gasification and pyrolysis, can be used to convert the energy contained in MSW into energy dense gaseous and liquid fuels. Although it is a more expensive method of generating electricity, the cost of these facilities can be offset by tipping fees.

Incineration or other forms of thermal treatment can be controversial public issues, due to perceptions regarding air emissions, ashes, odours, or removal of incentives to reduce waste generation. Some of these concerns could be alleviated through proactive municipal ordinances and waste diversion programs that remove packaging wastes, household hazardous wastes and other problematic components of MSW streams.

FOGs from restaurant and food services industries are also potential energy sources. Many of these materials are transported to Quebec, disposed of or composted. FOGs have high energy contents, and are best used as supplemental fuels with other biomass resources.

Municipal sources also generate biosolids from wastewater treatment processes. The energy potential of biosolids is small in comparison to other forms of biomass, but opportunities for its use are expected to be near load centres where population densities are high. The biosolids from wastewater treatment can be subjected to anaerobic digestion in sealed vessels to produce methane to provide heat for the treatment process, or if the economics are favourable, the methane can be burned to generate power.

Table 3.12 summarizes biomass sources from agriculture, forest and municipal sectors with some characteristics that can affect the feasibility of their development as energy sources.

Conversion Technology Development

There are several different conversion technologies capable of converting the energy in biomass to more useful forms, such as heat and power. Conversion processes can either turn raw biomass directly into heat by combustion or into other energy carriers such as combustible gas or liquid fuels. Converting biomass to other energy carriers can occur by biological (anaerobic digestion) or thermo-chemical means (gasification and pyrolysis). It is important to note that for power system planning, all biomass energy sources are thermal technologies. Whether or not an intermediate energy carrier is used to increase the density and reduce the volume of energy in biomass for transport or storage, all biomass to energy techniques result in a combustion cycle that produces heat or steam to generate power.

Biomass conversion technologies range from being commercially available in 2006 to being at various stages of research, development or demonstration. Some are available currently, but have little design, construction and operation experience in Ontario. Similar technologies may exist in different configurations for various applications, all of which may not be well suited for power generation. Biomass resources are variable in quantity and quality, thus the conversion process needs to be flexible in order to operate reliably.

A more detailed review of the conversion technologies that can transform the energy of these resources into grid-based power is presented in Appendix A. A brief discussion of the operability characteristics of each conversion technology is also included with a focus on its capability of providing controllable generation to contribute to meeting peak load requirements.

Table 3.12 – Biomass Energy Sources and Characteristics Affecting Feasibility of Development

Sector	Biomass Sources	Characteristics
Forestry and related products	Forest harvest residues	Distributed over large areas, varies year to year, logging practice can affect collection, permitting and ownership issues over feedstocks
	Silviculture	Distributed over large areas, varies year to year, may be expensive to collect, will be slow to implement (3-7 years)
	Unused annual allowable cut (AAC)	Issues over ownership of unused AAC, distributed over large areas, varies year to year
	Diseased and damaged trees	Distributed over large areas, no control over location, potential to import pellets from B.C.
	Mills and secondary industries	Most resources earmarked for other purposes, many mills are closing
	Dedicated wood plantations	Potential as a large source, high cost, higher environmental impacts
Agriculture and related products	Manure and livestock	Mostly water, expensive to transport, low energy density but high volume, treating manure to produce energy reduces pathogens thus addressing source water protection issues
	Crop and grain handling	Energy dense resource, limited resources, supplemental input only
	Greenhouses and nurseries	Fluctuating biomass production, concentrated resources as greenhouses are concentrated in clusters
	Off-spec, expired and spoiled feed	Inconsistent supplies in quantity and quality, can be energy dense
	Dedicated energy crops Meat plant wastes	Potentially the largest agricultural source, energy source must be purchased, diverts land from food production but provides farmers with alternative revenue stream (rural economic development) Potential pathogens, predictable quantities, consistent supply of resource
	Aquaculture and aquatic plants	Supply is assumed to be consistent with predictable characteristics, may be issues with collection and transport
Municipal sources	Landfill gas	Requirement for collecting landfill gas, feedstock has no or negative value
	Source separated organic MSW	Also addresses landfill issues, MSW streams contaminated with household hazardous waste, need for packaging and other waste regulations
	Leaf and yard residues	Amount of resource unknown, may already be composted at existing facilities
	Waste water treatment (biosolids)	Limited electricity generation capacity, potential contamination with metals and other hazardous materials
	Food processing industries	Potential high energy feedstocks, amount of resource unknown
	Fats, oils and greases (FOGs)	Potential supplemental input to biomass to energy facility, energy dense

Source: OPA, OMAFRA

3.5.1 Opportunities for Bioenergy Development

Over the last several years, there have been several estimates of the capacity of biomass to be converted to electrical energy. These estimates have spanned a large range in terms of potential electricity generation capacity and many have been based on theoretical statistical information and preliminary assumptions. The commercial and policy barriers to implementation of biomass energy projects, including competing uses for biomass, would need to be addressed for the estimated potential to be realized. A summary of estimates prepared by different organizations of the potential for biomass to generate electricity in Ontario is presented in Table 3.13.

Table 3.13 – Estimates of Biomass Capacity for Electricity Generation

Source	Estimate (MW)	Comments
CanBIO, 2003	1,700	Figure based on compilation of third party estimates
Etcheverry *et al.*, 2004	2,450	All biomass projected 10-20 years in the future
Pembina and CELA, 2004	800	All biomass by 2020
Pollution Probe and Summerhill Group, 2004	480	Includes biomass, biogas and MSW

Note:BIOCAP Canada has estimated the energy content of Ontario's biomass resources to be over 80 TWh. This is, by far, the largest estimate of bioenergy potential, but it is assumed that this figure does not reflect constraints of location, environmental considerations or economic viability.
Sources:CanBIO, 2003, Ontario's Biomass Opportunities, Presentation to the Electricity Conservation and Supply Task Force. Etcheverry, Jose, Paul Gipe, William Kemp, Roger Sampson, Martjin Vis, Bill Eggertson, Rob McMonagle, Sarah Marchildon and Dale Marshall, 2004, Smart Generation: Powering Ontario with Renewable Energy, David Suzuki Foundation.
Pembina Institute for Appropriate Development and Canadian Environmental Law Association, 2004, Power for the Future: Towards a Sustainable Electricity System for Ontario. Pollution Probe and Summerhill Group, 2004, Report on the Green Power in Canada Workshop Series.

Table 3.14 shows the planning assumptions that we have made for inclusion in the preliminary IPSP. These figures are not intended to reflect assumptions about the theoretical or achievable potential for biomass electrical capacity in Ontario. This information is presented here to stimulate discussion and feedback from stakeholders on appropriate assumptions for the IPSP. The planning assumptions reflect uncertainties and barriers to biomass energy development in both the near and long term in the IPSP. These barriers are discussed in the following section.

Table 3.14 – Preliminary Planning Assumptions for Biomass Capacity

Sector	Planning Assumption: Electricity Generation Capacity (MW)[1,2]		
	2010-2015	2016-2027	Total
Landfill gas and MSW	100	245	345
Forestry	100	260	360
Atikokan	--	200	200
Agriculture	100	245	345
Total	300	950	1,250

Notes: 1. These figures represent planning assumptions only and are not intended to reflect OPA's estimation of biomass to electricity generating potential.
2. OPA is seeking stakeholder input and expert advice regarding the potential for biomass to generate electricity in the IPSP.
Source: OPA

3.5.2 Barriers and Costs

A number of barriers to developing biomass energy projects have been identified in researching the potential for biomass generated power in the IPSP. Some of these barriers, including economic, policy and institutional factors are identified in this section. The notion of wide-scale biomass and MSW to energy development is a complex subject area, as it supposes that an industry with associated supply chains, expertise and investments will develop despite the lack of knowledge and certainty regarding the resources, technologies and capability for system integration. Addressing these barriers will necessitate collaboration among multiple provincial government ministries, municipal regulators and other stakeholders.

A summary of some institutional and policy barriers affecting biomass to energy development include the following:

- subjective or inappropriate interpretations of biomass energy processes, feedstocks and bio-energy products
- restrictive land use permit requirements by municipal authorities
- onerous procedures and costs associated with environmental assessment, certificates of approval, connection costs and permitting requirements
- lack of incentives to reflect values to rural development and the environment that are supplemental to the value of electricity that biomass projects can generate
- the cost of other energy sources that are in competition with biomass resources.

Some additional challenges to biomass energy development have been identified that are technical or social in nature, including the following:

- lack of knowledge related to the location and character of the biomass energy resources, which tend to be highly distributed and locally managed
- logistical and economic challenges arising from the small-scale nature (less than 10 MW) of biomass conversion technologies
- technical and economic challenges associated with connection of small generation facilities to distribution and transmission networks

- lack of local supply chains, expertise and operation and maintenance experience with biomass energy systems
- adequate provision of information and knowledge transfer roles regarding the technologies and applications available to harness energy from biomass.

Biomass energy projects are currently more expensive than conventional, competing generation options. While experience with these systems will help to reduce the costs of design and construction, opportunities for increasing cost-effectiveness of these projects are not well documented. A survey of the capital and operating costs associated with biomass projects worldwide shows that costs span a wide range. A summary of costs for various biomass to electricity plants is summarized in Table 3.15.

Table 3.15 – Estimated Costs of Biomass to Electricity and Combined Heat and Power Projects

Biomass Energy Project	Sector	Unit Energy Cost ($/MWh)
Anaerobic Digestor	Agriculture	140 – 190
Atikokan Wood Waste Conversion	Forestry/coal replacement	89 – 115
Austria CHP Plant	Multiple sources	124 – 144

Source: OPA, Martin Lensink, OMAFRA, FBI (Atikokan Report), OECD (Projected Costs of Generating Electricity-2005 update).

3.5.3 Potential for Bioenergy in Electricity

Through the stakeholder engagement process, OPA is interested in information, experience or guidance from interested parties that will assist in understanding the nature of biomass resources available to Ontario, costs and operational characteristics of conversion technologies, and appropriate strategies for integrating grid-connected biomass energy sources. OPA is seeking information regarding opportunities for biomass energy in the near term, approaches for increasing opportunities for biomass in the longer term, and guidance for addressing barriers to biomass energy development.

Through the forthcoming Standard Offer Program (SOP), OPA is prepared to accept any biomass projects that meet the contract conditions of the Standard Offer. While the SOP price cannot pay for all biomass to energy projects, it should make the development of some biomass projects economically feasible.

Planning to integrate biomass energy into the power system is challenging because OPA is not a project proponent. Thus, even if the resource is plentiful, developers will need to conduct their own feasibility studies and initiate the development of power plants utilizing these resources. OPA does not have authority to direct the use of Ontario's biomass resources. Prospective developers have interest in biomass for end-uses higher on the value-added chain than electricity – such as transport fuels, thermal energy, polymers or chemicals. While some of these uses could compete with electricity, there is potential for others to complement the generation of electricity.

OPA is seeking input and insight from interested parties regarding the above issues. In addition, OPA is seeking advice in addressing the following questions:

- Where are concentrations of biomass large enough to justify business cases for developing electricity or combined heat and power projects?
- How can Ontario maximize experience and learning potential to catalyze a bioenergy market in Ontario (for example by installing a working anaerobic digester at a university or community college)?
- How can biomass power projects be developed to fully exploit the controllable nature of biomass energy sources to meet peak demand and load-following requirements?
- How can social benefits of biomass projects, such as rural economic development and environmental protection, be best utilized and compensated for?

4. New Conventional Resources

This section provides an overview of the potential for new conventional resources that will be considered in the development of the IPSP.

The IPSP will refine supply mix advice estimates for the conventional generation energy contributions from nuclear and natural gas, identify potential siting options, develop timelines for new supply approval and construction periods and discuss operational implications of nuclear and natural gas plants in the overall resource mix.

4.1 Nuclear Generation

4.1.1 Recent Information and Analysis

In June 2006, the Minister of Energy directed OPA to "plan for nuclear capacity to meet base-load electricity requirements but limit the installed in-service capacity of nuclear power over the life of the plan to 14,000 MW."

In doing so, Ontario joined jurisdictions such as the United States, Finland and the United Kingdom in recognizing that nuclear energy can play a role in securing and meeting future electricity needs without contributing to global climate change.

With the capacity envelope well defined by the government, Ontario's nuclear generating companies have undertaken a range of initiatives to analyze their options within the scope of the directive.

Leveraging experiences gained during earlier and ongoing restart projects at the Bruce A and Pickering A stations, independent studies were launched and existing ones advanced to consider detailed aspects of the economic and technical challenges involved with future refurbishments at the Pickering B and Bruce B stations.

In addition, site license applications have been filed with the Canadian Nuclear Safety Commission (CNSC) for the potential construction of new nuclear units at the Bruce and Darlington facilities. Ontario's nuclear generators are being consistent with the Minister's directions to the OPA by carrying out necessary assessments as part of the planning and environmental assessment process for new build. This approach is also consistent with the *Canadian Environmental Assessment Act* (CEEA), which is a key element to consider in any new nuclear project in Ontario.

In keeping with the government's desire to make decisions based on the best technology offered at the best price to ratepayers, Ontario's nuclear generators have also initiated assessments of several reactor designs to develop a better understanding of their potential safety, environmental, social and commercial impacts.

Given the long lead times associated with new build or refurbishments, the need for such long-term planning is vital if nuclear energy is to maintain its current contribution to Ontario's supply mix.

Between 2014 and 2020, the bulk of Ontario's nuclear facilities will have reached the end of their current service life, placing significant importance on the integration and coordination of refurbishment outages and replacement generation. This impacts not only the nuclear energy sector in Ontario but also transmission and planning entities.

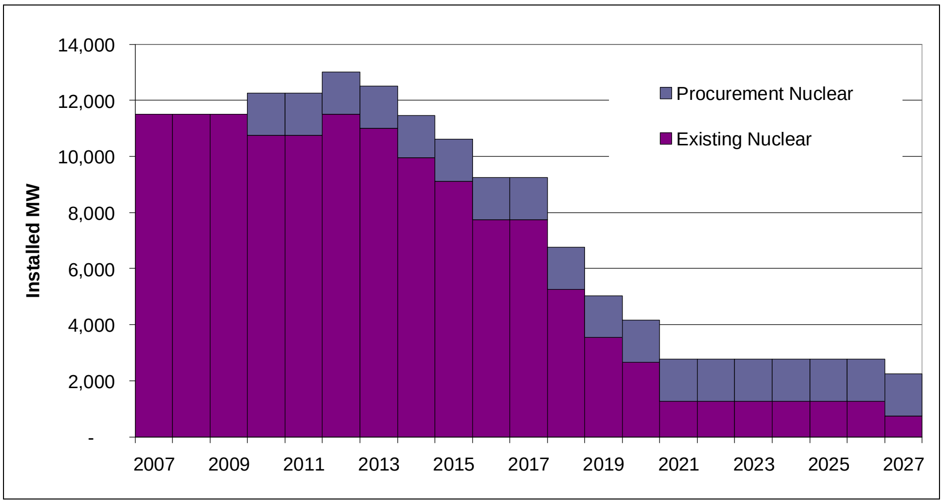
In the IPSP, the OPA will describe the actions necessary to keep refurbishment options available for Ontario's existing nuclear facilities. Based on the expected timing for the end of the existing nuclear stations, the need to plan for construction of new nuclear stations will also be identified.

4.1.2 End-of-Life Estimates and Current Refurbishments

As shown in Figure 4.1, it is projected that most of Ontario's nuclear units would reach the end of their service lives by 2020 and all by 2036. This will result in a significant decline in capacity over the period, even after taking into account the recent decisions to refurbish the Bruce A station.

The service lives of the nuclear units are determined by the life of major components such as fuel channels, steam generators or feeder pipes reaching their technical or economic end-of-life. Without refurbishment, most of the associated capacity reductions resulting from nuclear units ceasing operation would occur in the period from about 2014 to about 2020, with all nuclear units offline except some of the Bruce A units which will be out of service by about 2027. Should Ontario's nuclear generating companies opt not to refurbish units as their end-of-life dates approach, capacity reductions will be felt most deeply between 2014 and 2020, with further reductions occurring around 2027.

Figure 4.1 – Declining Capacity of Ontario's Existing Nuclear Units without Additional Refurbishments



Source: OPA

As mentioned earlier, Ontario's nuclear industry has recent and ongoing experience with large-scale refurbishment projects.

In October of 2005, the OPA and Bruce Power executed an agreement for the restart of Bruce A Units 1 and 2, which will contribute an additional 1,500 MW of baseload capacity through 2036. Bruce Power also intends to refurbish Unit 3 and extend the operating life of Unit 4 as part of its $4.25 billion investment program. Although OPG has indicated it will not refurbish Pickering Units 2 and 3, it has recently announced that it will conduct an Environmental Assessment and feasibility study of the technical and business merits of refurbishing the four Pickering B units, with a decision expected in early 2008. The OPA continues to assess the impacts of nuclear generation retirement and potential refurbishment or new build on the demand-supply balance.

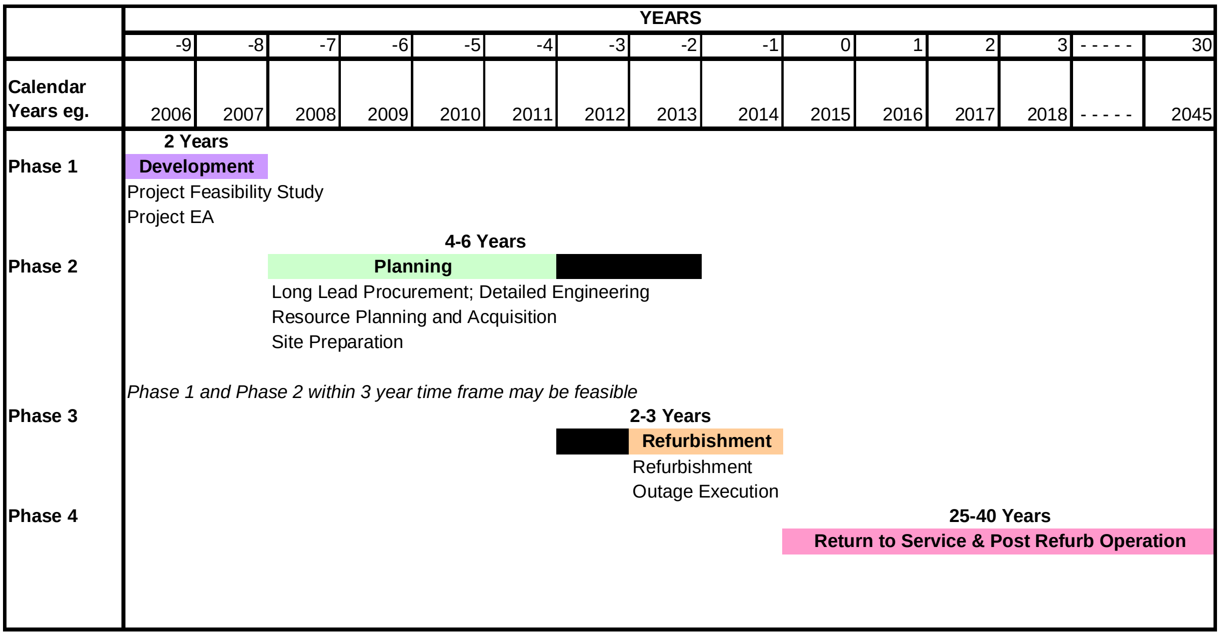
4.1.3 Importance of Coordination

The OPA is working closely with the province's nuclear generators to ensure that nuclear resource information remains current for planning purposes, given the significant role of nuclear generation in Ontario's electricity system. Based on a business decision by either OPG or Bruce Power to undertake refurbishment of one or more nuclear units at an existing site, close coordination of refurbishment outages will remain essential because the availability of skilled labour, long lead-time equipment and critical material resources can adversely impact scheduled completion dates and cost. With 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 the specialized companies needed to complete their complex installations.

To help manage the demographic challenges they face, Ontario's nuclear generators have forged ties in recent years with trade unions, provincial colleges and universities to establish scholarships and apprenticeship programs to promote skilled trades as an alternative for recent high school graduates. Still, with an aging workforce in all sectors of Canadian business, the nuclear industry will have to compete hard to attract skilled workers needed for any major rehabilitation projects.

Should business cases be made for future refurbishments, Ontario's nuclear operators expect a typical refurbishment to last approximately two to three years. However, the planning phase involving environmental assessments, detailed engineering and ordering of long lead-time materials, such as steam generators, would need to be initiated several years in advance of the actual refurbishment outage. Figure 4.2 provides a typical timeline for a refurbishment decision and project execution.

Figure 4.2 – Typical Timeline for a Refurbishment of a Nuclear Unit

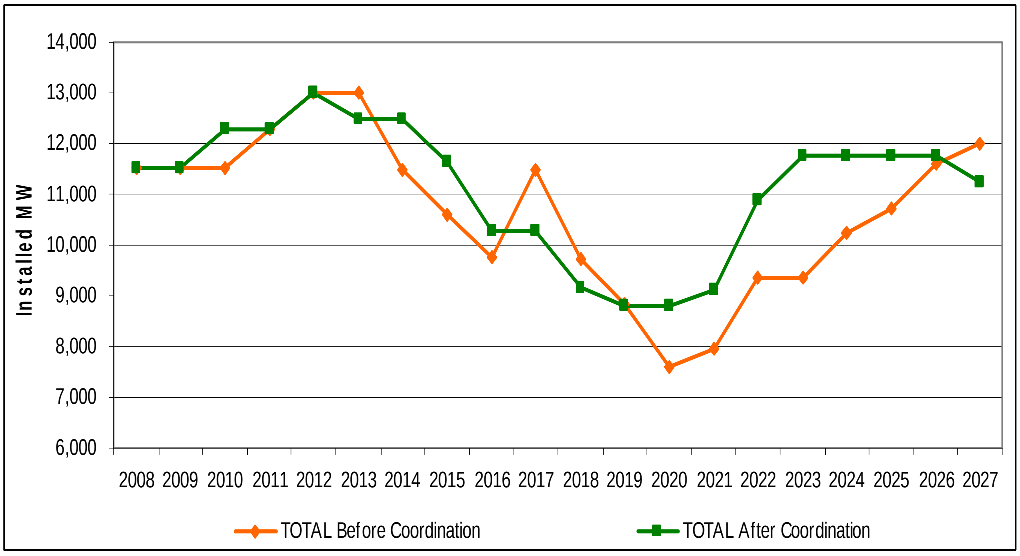


Source: OPA (information provided by Bruce Power and OPG).

Given their relatively long lead times, and the fact that any refurbishment outage represents a temporary reduction in large amounts of capacity, such projects require a considerable degree of advance coordination to manage impacts on the reliability of the power system.

Figure 4.3 illustrates the importance of a clear focus on coordination and allows an appreciation of the impacts on the total demand and supply situation for Ontario of three, four or five units out at a time. The goal is to maximize available capacity at all times, while at the same time reduce the need for expensive backup generation for reliability.

Figure 4.3 – Uncoordinated vs Coordinated Refurbishment of Nuclear Units and their Impacts on Available Capacity



Source: OPA

Working with information from Ontario's nuclear companies concerning unit retirement, refurbishment and outage schedules, the IPSP will identify the timing considerations and other challenges associated with each of the nuclear options – refurbishment of existing plants, timelines for new build and the site selection process for new build. For example, constraints related to the availability of skilled labour for refurbishment projects have been identified and this will remain a key challenge as the nuclear industry begins to develop specific projects including new build.

The OPA has gained a better understanding of the issues and the decision-making processes in support of the refurbishment decisions and has identified several factors that are important to take into consideration on nuclear issues. They include:

- lessons learned from rehabilitation experience in Canada and elsewhere
- project management and assessment approach to decision-making
- recent performance and cost
- clarity around environmental assessment and safety requirements for refurbishment
- management of wastes arising from refurbishment, nuclear fuel waste disposal and decommissioning issues.

4.1.4 Lessons Learned

Rehabilitation Experience in Canada and Elsewhere

While the most recent rehabilitation of units at Ontario's nuclear stations have been generally viewed as economically and technically sound ventures, they were the beneficiaries of harsh lessons learned from earlier attempts.

Domestically, the first nuclear refurbishment projects began in the mid-to-late 1980s, when the former Ontario Hydro replaced the main components of the fuel channel assemblies in the four Pickering A units. These "retubed" units were successfully returned to service and the station was operated until the end of 1997.

By the spring of 1998, all of the units at both Pickering A and Bruce A were shut down and laid up as part of what Ontario Hydro called its Nuclear Asset Optimization Plan.

Although the original plan was to return the four Pickering A units to service between 1999 and 2001, the first unit did not come back online until 2003 and encountered severe cost and schedule overruns. As a result, in December of 2003, the Minister of Energy charged the OPG Review Committee[5] with the task of providing advice and guidance on the potential refurbishment of the remaining Pickering A units.

That committee recommended a high level of due diligence, including a detailed business case analysis, be applied to any decision on the future of those units. The application of a rigorous, well-structured approach to major investments subsequently led to a decision not to refurbish Pickering A Units 2 and 3. The risks of the undertaking were judged not commensurate with the expected returns of a commercially driven enterprise.

However, Pickering Unit 1 was successfully returned to service in 2005 with generally acknowledged better cost and schedule control than that of Pickering Unit 4.

Meanwhile, Bruce A Unit 3 was successfully returned to service in October of 2003, followed three months later by Unit 4, at a combined investment of $750 million. Lessons learned about scope and project management needs for such a large-scale rehabilitation gave Bruce Power and its private sector partners enough confidence to then launch a wide-ranging feasibility study in January of 2004 to consider the further restart of Units 1 and 2, the refurbishment of the Bruce B units when required and the potential of building new reactors at the Bruce site.

In October of 2005, Bruce Power announced that it had executed an agreement with the OPA and soon after launched its ongoing, $4.25 billion project to restart the remaining two Bruce A units, replace the main components on Unit 3 and extend the operating life of Unit 4. One year into the project, Bruce Power has reported that it remains in line with its cost and schedule estimates.

[5] The Hon. John Manley, P.C.,M.P., B.A., LLB, Chair, The Hon. Jake Epp, P.C., B.A., B.Ed., LL.D
Peter C. Godsoe, O.C.

With lessons learned from its own refurbishment projects, OPG has indicated that extensive efforts are currently underway to provide the analysis in support of developing the business case for refurbishment of Pickering B. The considerations include:

- preparation of a comprehensive and detailed definition of the refurbishment scope and completion of activities such as plant condition assessments, integrated safety review and life-cycle investment strategies for the assets
- initiation of the Environmental Assessment process. The results of this process will be incorporated into OPG's decision-making around the refurbishment
- development of detailed cost estimates to be obtained through vendor quotes, preliminary engineering and other activities targeted to narrowing the uncertainty in cost estimates, including formulation of alternative contracting strategies for the refurbishment work
- assessment of the availability of industry resources to perform refurbishment activities and work with industry partners to ensure availability of requisite skilled trades.

Canadian Experience

In addition to planning and development phase refurbishment work at Bruce A, and Pickering B, similar work is underway at the Gentilly 2 site (Hydro Quebec) and at the Point Lepreau site (New Brunswick Power). Atomic Energy Canada Limited (AECL) is playing a major contracting role at all three facilities- planning, design, scheduling and execution of the reactor retube work (fuel channel and feeder replacements). Babcox & Wilcox is manufacturing the replacement steam generators for the Bruce A restart while Canadian Power Utilities Services, SNC Lavalin and Wardrop Engineering have all provided contracted services to these projects in the area of plant condition assessments, feasibility studies and regulatory reviews.

The CNSC has recently issued several documents outlining the regulatory expectations required for both plant refurbishments and new build.

Meanwhile, the CANDU Owners Group (COG) has established a working group, with representatives from OPG, NB Power, Hydro Quebec, Bruce Power and South Korea to share experiences and focus on major issues associated with refurbishment work.

International Experience

India has embarked on a very large refurbishment effort to replace the fuel channels, feeders and some steam generators at seven of its Pressurized Heavy Water Reactors (PHWR) plants.

South Korea is also embarking on a program to refurbish its CANDU reactor at Wolsong 1. It has contracted AECL to plan, design, schedule and execute the fuel channel replacement portion of its refurbishment outage. South Korea is also performing detailed life extension assessments, with the intention to begin future refurbishments on the remaining nuclear power plants.

Argentina is also starting on refurbishment efforts at its CANDU plant at Embalse and has contracted AECL to begin the plant condition assessment and to prepare pre-planning estimates for retubing.

Japan is also beginning refurbishment efforts on its nuclear power plants.

In the United States, various utilities which own and operate nuclear power plants have been in license renewals (life extensions) of a large number of plants while the Nuclear Regulatory Commission continues to streamline the regulatory processes for refurbishments. For example, the Tennessee Valley Authority (TVA) has successfully restarted two of the three units at the Browns Ferry Nuclear Plant that had been shut down since 1985. Unit 2 returned to service in 1991 and Unit 3 in 1995. TVA has been doing extensive work on Unit 1 and said it expects to have the unit ready to begin operating in May 2007. The final unit is expected to return to service in 2007 as part of an estimated $1.8 billion, 60-month recovery project that company officials say is on budget and schedule. In addition to the restoration of Unit 1, TVA is increasing the capacity at all three Browns Ferry units to 1,280 MW, increasing the total capacity of the station to 3,840 MW from 3,297 MW when built in the 1970s. The licenses for the units have been extended by 20 years.

The International Atomic Energy Agency (IAEA) recently published several technical guidelines for assessing refurbishment costs, continued plant viability and material degradation impacts, determining plant condition, and several other life extension related products. The IAEA will be hosting a major symposium in China in 2007 to focus on worldwide issues associated with Nuclear Power Plant Life Management.

Investment Decision Making

A rigorous and well structured approach for investment decisions and long-term careful planning approach adopted by proponents provides confidence that all important factors have been considered and the assessments are robust and comprehensive. In particular, the focus on an early commitment to maintaining options for procurement of long lead-time equipment and a detailed understanding of the skills and human resource availability is appropriate. Emphasis on use of accepted methodologies for optimization against multiple criteria, use of alternatives and scenario analyses, detailed risk assessments, and the use of appropriate financial factors and modelling is part of this approach.

OPA understands that such an investment review process is being conducted or considered by OPG related to the future refurbishment of Pickering B and Darlington. A similar process is being followed by Bruce Power. Ontario's nuclear generators are in the process of gathering information on the present state of their assets, understanding the work to be done and the level of continued investment over the remaining life of the plant to achieve the desired level of performance.

Managing Risk and Uncertainty

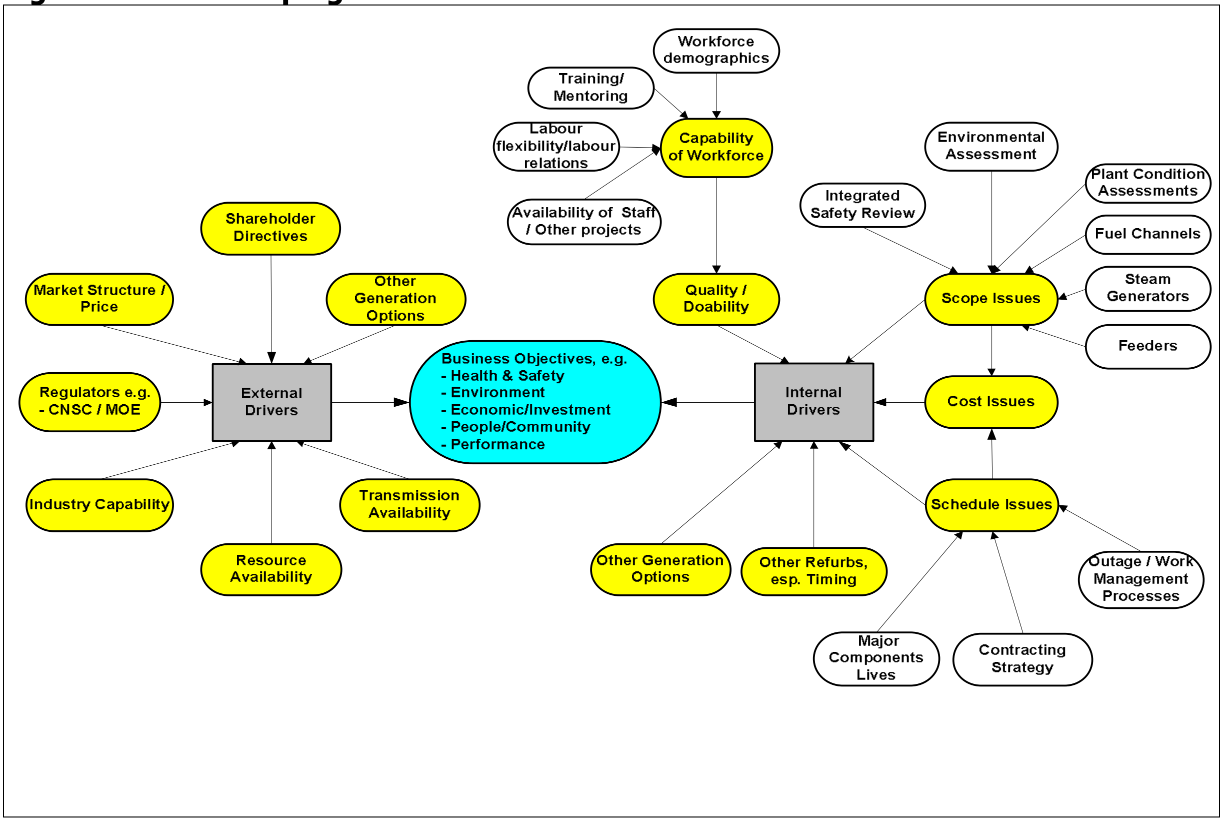
Extensive information on the risks associated with achieving the desired operating life goals need to be addressed prior to a decision on refurbishment. As an example of the comprehensive approach to an assessment of project risks, the following aspects are being addressed by OPG as part of its review of Pickering B refurbishment:

- multiple reviews of cost estimates and schedules with internal and external experts on both refurbishment and post-refurbishment costs as well as expected life and performance
- comparisons of cost and schedule estimates for the Pickering B refurbishment with similar ongoing refurbishments (e.g., Pt. Lepreau and Bruce A) as well as relevant international experience
- development of range estimates (confidence levels) for all inputs to the assessment, including refurbishment costs, ongoing costs and performance expectations
- detailed modelling, including sensitivity analysis of results to all major inputs, and Monte Carlo simulation to determine overall confidence ranges of results
- a stage-gate approach to decisions provides an increasing level of confidence one step at a time. For example, a successful completion of a screening level assessment is the first step in a decision before proceeding to the next level of commitment in terms of resources.

OPG has indicated that for the Pickering B screening level assessment, a conservative approach was taken to estimating costs and performance using the best available information about the state of the plant, similar projects elsewhere, OPG's experience on similar major projects, and lessons learned. OPA understands that the conclusion of the preliminary screening level assessment conducted by OPG on Pickering B was that the initial estimates of the economics of refurbishment merit continuing the scoping activities with a focus on reducing uncertainties around project costs and expected production levels.

Figure 4.4 provides a schematic representation of the issues generally considered in developing a detailed business case for refurbishment and illustrates the complexity of the analysis.

Figure 4.4 – Developing the Business Case for Refurbishment



Source: OPG

4.1.5 Performance and Cost

Any decisions Ontario's nuclear generators make regarding refurbishments will be influenced by the expected performance of the units, as well as forecasts of ongoing operational and maintenance costs over the post-refurbishment life.

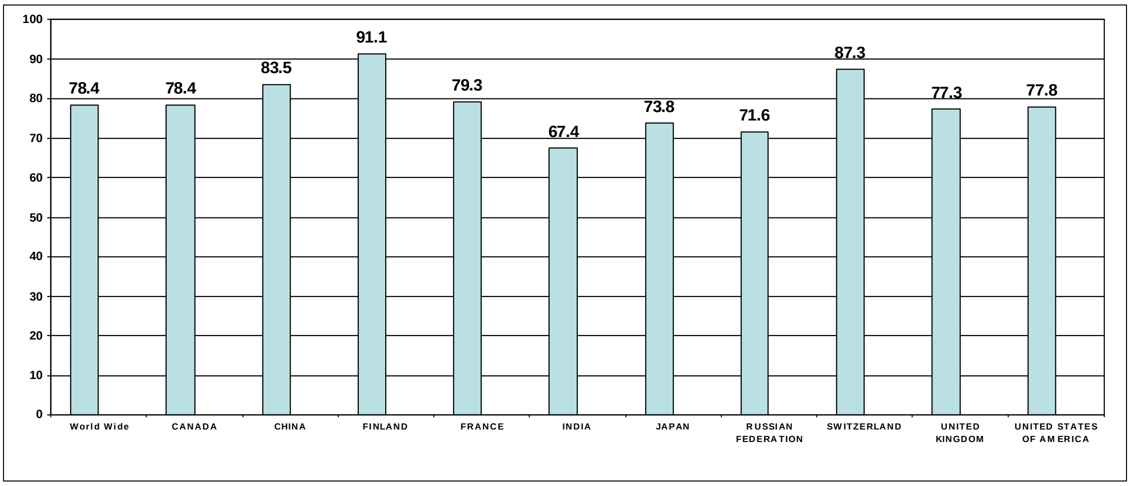
Historical Performance

OPA has reviewed the available data on performance of Ontario's nuclear reactors from the time each unit was brought into service. The performance was summarized previously (see Table 2.3 and Figure 2.2). The performance of the Canadian reactors as a group against international experience is also highlighted. Nationally, the lifetime capability factor of Canadian reactors was 78.4 percent, which matches the world average as illustrated in Figure 4.5.

The lifetime operational performance for all Ontario units is shown in Figure 4.6. The data pertains to full years of commercial operation and excludes those years when Pickering A and Bruce A were shut down for extended periods, starting in 1997. The extended outages were related to a conscious decision made by Ontario Hydro, in 1997, to lay-up the operating units at

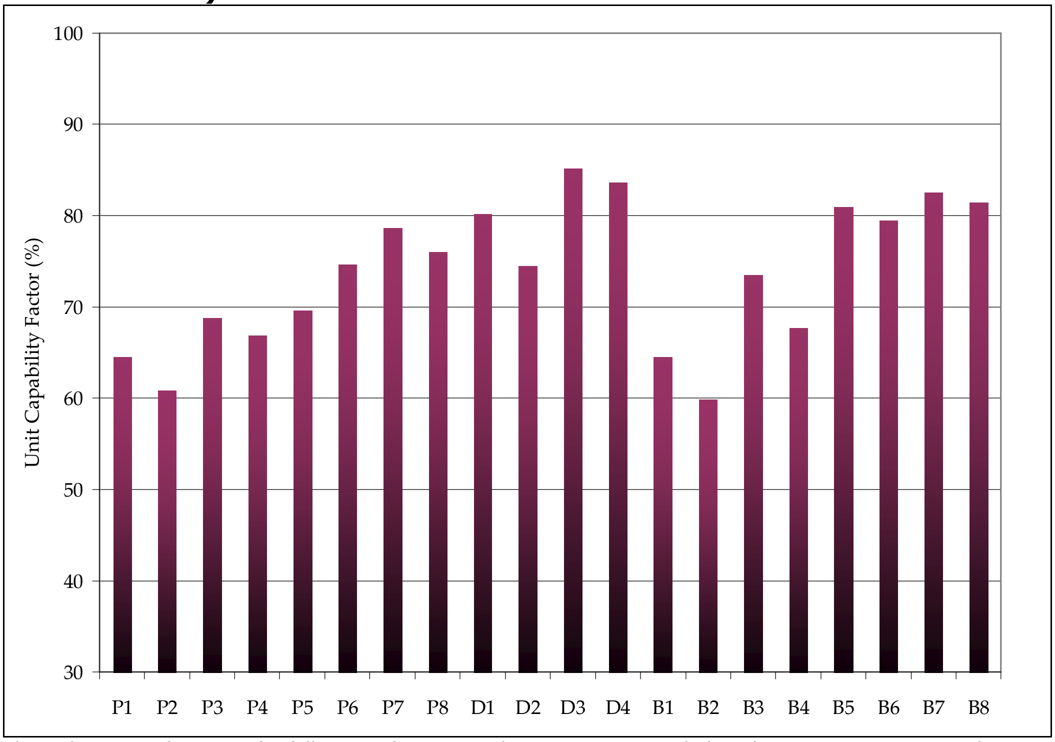
Bruce A and Pickering A. The units were shut down to allow resources to be engaged in improving the operation of Ontario Hydro facilities at Pickering B, Bruce B and Darlington.

Figure 4.5 – Performance of Nuclear Plants Worldwide



Note: Measures Lifetime Unit Capability Factor (until 2005)
Source: WANO

Figure 4.6 – Lifetime Operational Performance (Unit Capability Factor, %) for all Ontario Units



This indicates performance for full years of commercial operation, i.e., excluding those years units were taken out of service for an extended outage due to plant condition.
Source: yearly data from IAEA 2005 Operating Experience with Nuclear Power Stations (Power Reactor Information System).

Recent Performance

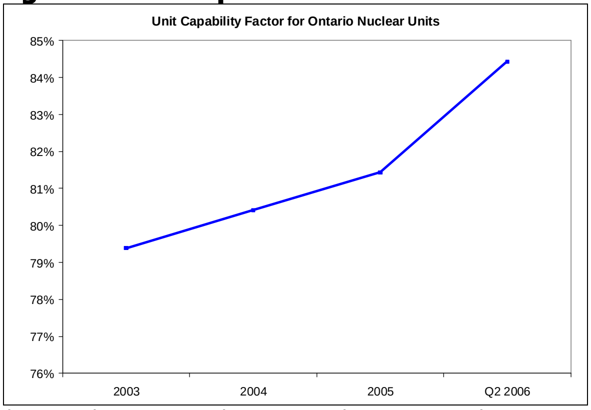
The Canadian nuclear industry's focus on operations and maintenance practices and investments in material improvements have resulted in a trend towards increased output and reliability, as seen through higher capacity factors and lower forced outage rates.

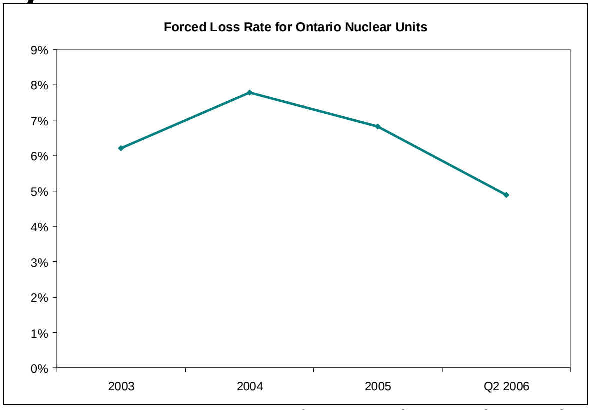
In 2005, Ontario's reactors generated 82,970,000 MWh of electricity, an increase of 2.3 percent over 2005. The capacity factor for all the units was 78.59 percent, compared to 77.66 percent for 2004. Both OPG and Bruce Power have reported improved performance trends. For example, production from the Bruce site has increased by roughly 60 percent since 2001, reflecting improved asset management and the return to service of Bruce A Units 3 and 4.

This trend has continued into 2006 with the Ontario nuclear units generating substantially more electricity (10 percent or higher) during the first six months of 2006 compared to the same period a year ago.

Recent performance of enhanced reliability is illustrated in Figure 4.7 showing that capability factors (a measure of the percentage of time that nuclear units are available to generate electricity in a particular period) have improved from approximately 79 percent in 2003 to 84 percent in 2005.

Figure 4.7 – Improved Production Reliability of Ontario's Nuclear Units





The Forced Loss Rate indicator is used to monitor industry progress in minimizing outage time and power reductions that result from unplanned equipment failures, human errors, or other conditions during the operating period (excluding planned outages and their possible outage extensions). The indicator reflects the effectiveness of plant programs and practices in maintaining systems available for safe electrical generation when the plant is expected to be at the grid dispatcher's disposal.
Definition: The forced loss rate (FLR) is defined as the ratio of all unplanned forced energy losses during a given period of time to the reference energy generation minus energy generation losses corresponding to planned outages and any unplanned outage extensions of planned outages, during the same period, expressed as a percentage.
Source: World Association of Nuclear Operators

Improving capability factors are attributable to a number of factors such as the reduction in the Forced Loss Rate (unplanned outages) of the nuclear units, which is a testament to the improving material condition of the plants. Another factor is a reduction in planned outage time, as Ontario's nuclear operators wrap up major maintenance programs that have been underway for the last several years. As shown in Figure 4.7, forced loss rates have been reduced from over 8 percent in 2003 to just over 5 percent in 2005 and are projected to be below 5 percent at year-end 2006.

Nuclear Costs – Refurbishments

Refurbishment of nuclear units is expected to be cost competitive with other options for meeting the supply demand gap. As previously mentioned, Bruce Power executed an agreement with the OPA in October of 2005 regarding the refurbishment of Bruce A units. The contract provided for $57.37/MWh (5.7 cents/kWh), plus fuel costs for all Bruce units, escalating at consumer price index (CPI). Thus, the refurbishment of Bruce A units is expected to result in a power cost comparable to other generation options.

Similarly, in July of 2005, the Government of New Brunswick announced that NB Power will proceed with the refurbishment of the Pt. Lepreau CANDU nuclear generating station. New Brunswick Power[6] estimated that the cost of power from the refurbished Pt. Lepreau station will be approximately 5 cents/kWh ($2006), which compares favourably to other generation options.

Using a conservative approach and factoring its experience from the refurbishment of two of the Pickering A units, OPG has indicated that its preliminary assessment of the likely cost of

[6] Pt. Lepreau, Evaluation, Integrated Resource Plan, February 2002, NB Power.

power from the refurbishment of the Pickering B station compares favourably with the cost of other generation options. As noted earlier, OPG is continuing the scoping activities with a focus on reducing uncertainties around project costs and expected production levels.

In developing the IPSP, the OPA intends to present comparative evaluations of the various options, while remaining neutral towards the project proponents and nuclear technologies. Decisions on refurbishment will be driven largely by the proponents. If the terms are in the public interest, it will be contracted for. Scenarios of feasible refurbishments will be reflected in the IPSP.

4.1.6 Environmental and Safety Requirements

Environmental Assessment Requirements for Refurbishment

In Canada, a pre-condition for the refurbishment and return to service of power reactors is that a screening level Environmental Assessment (EA), as defined by the *Canadian Environmental Assessment Act (CEAA)*, is performed by the proponent and accepted by the CNSC. The process and timeframes for carrying out a screening level EA are now well established and take approximately two years.

EAs have been undertaken and accepted by the CNSC for the restart of Pickering A and Bruce A and for waste management facilities, similar to those that may need to be constructed to safely manage waste produced by the potential refurbishment of other Ontario nuclear units.

First of a kind EAs have also been recently completed for the continued operation, including refurbishment, of Bruce A and B until 2043. Approved EAs allow the operator to proceed with refurbishment when required, consistent with CEAA requirements. Environmental assessments for refurbishment at Darlington and Pickering B can build on the experience gained in recent years through the Pickering A, Bruce A and B assessments. EAs can be used as planning tools and can begin prior to any decision to proceed with a refurbishment or other project.

OPG has recently initiated the EA for the refurbishment of Pickering B. The Project Description establishing the scope of the EA was submitted to the CNSC in June 2006.

Successful Environmental Assessments have also been completed for the use of a new fuel design at the Bruce Power facilities and for modifications to the Solid Radioactive Waste Management Facility (SRWMF) at the Pt. Lepreau site.

Since the process is well defined, there is high confidence that Environmental Assessments for future refurbishments will be timely and well-managed.

Safety Requirements

In May of 2006 the CNSC issued Draft Regulatory Guide G-360 Life Extension of Nuclear Power Plants. The guide informs licensees about the steps to take and phases to consider when undertaking a project to extend the life of a nuclear power plant. The scope of the guides identified the elements to consider when establishing a life extension project and considerations to be taken into account in managing and executing the project.

The prime requirement of G-360 is for the licensee to carry out a comprehensive Integrated Safety Review (ISR) in accordance with the requirements of the Periodic Safety Review of Nuclear Power Plants (PSR) Safety Guide published by the International Atomic Energy Agency (IAEA) and additional reviews with respect to quality management, security and safeguards. The objective of these reviews is to determine to what extent the plant conforms to modern high level safety goals and requirements, the adequacy of the arrangements in place to maintain plant safety during longer-term operations and to identify improvements to resolve issues that have been noted. After completion of the ISR, G-360 requires the licensee to develop a Safety Improvement Plan (SIP) for submission to the CSNC. The SIP integrates all necessary and cost-effective corrective actions identified by the ISR process including, proposed plant modifications, safety upgrades, compensatory measures and improvements to operations and management programs.

By using an iterative approach, proponent and regulatory staff are expected to be able to resolve issues as the project progresses. Given the experience the Canadian nuclear industry has gained with respect to refurbishment and returning shut-down reactors to service, the safety issues risks associated with refurbishment of Ontario's nuclear power plants are expected to be manageable.

4.1.7 New Nuclear

In the *Supply Mix Advice Report* issued in December of 2005, the OPA advised that new nuclear plants should be contributors to meeting the expected 21,000 MW gap between supply and foreseen demand by 2027.

In June of 2006, the Minister of Energy directed OPG to "begin a federal approvals process, including an environmental assessment for new nuclear units at an existing facility."

By September, Bruce Power and OPG had each filed applications for Site Preparation Licenses for new nuclear units at their Bruce and Darlington sites respectively. The process of obtaining all of the necessary approvals for new nuclear units is a long one. The many approvals required fall mainly under the jurisdiction of the CNSC. A summary of the requirements is discussed below and a typical timeline for approval is shown in Figure 4.8.

The construction and operation of a new nuclear power plant requires five licenses from the CNSC, as follows:

1. Site Preparation License
2. Construction License
3. Operation License (renewable every several years)
4. Decommissioning License
5. Abandonment License

At each stage, the proponent must satisfactorily demonstrate conformance with all applicable laws and regulations and that the pre-requisites required for that license to be granted have been met. For example, a pre-requisite for issuing any license for new nuclear plants is the satisfactory completion of a Comprehensive Federal Environmental Assessment under the *Canadian Environmental Assessment Act*. Before the CNSC will grant approval, the Environmental Assessment must show that the project is not likely to cause significant adverse environmental effects with the available mitigation measures.

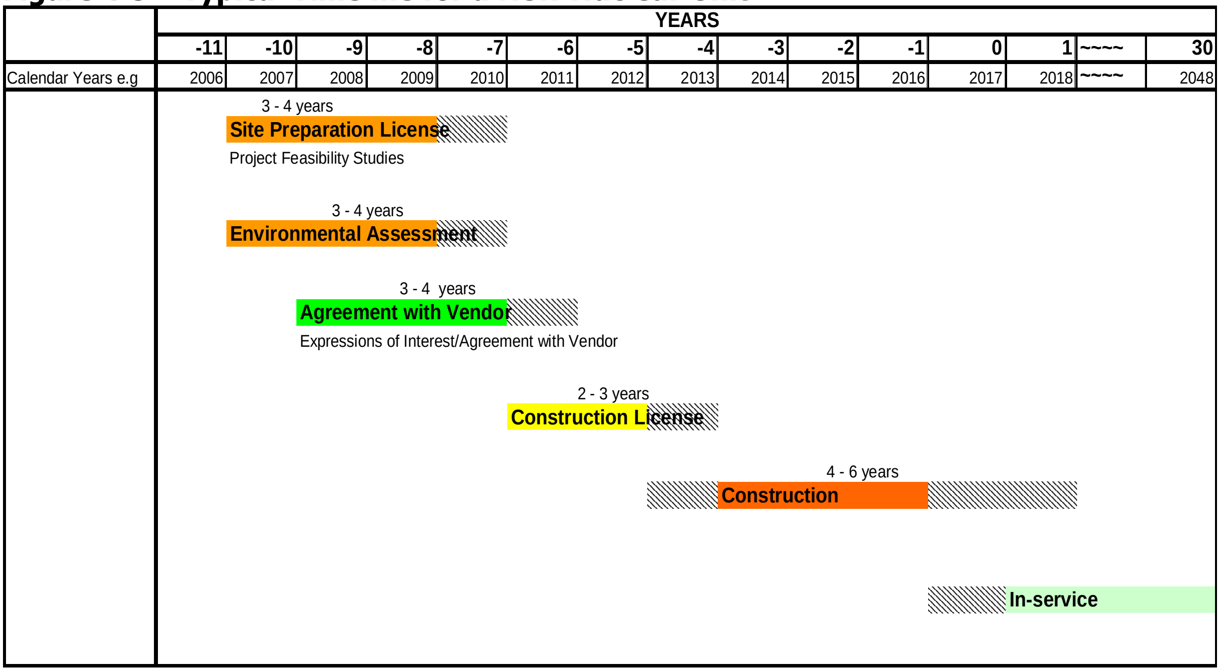
This EA process combined with construction and commissioning lead times for the first unit can range from 9 to 12 years. Decisions need to be made in a timely manner if the option of utilizing new nuclear to meet the expected supply gap is to be preserved. Given the long lead times, we believe that Environmental Assessments, Licensing activities and feasibility studies of new nuclear units should be actively pursued in order to keep this option viable for meeting the supply gap. Depending on the outcome of feasibility studies of refurbishment, new nuclear units may prove to be key to addressing the forecast supply demand gap in the 2015 to 2025 time period.

Approvals and Siting Considerations

Siting considerations for nuclear stations are complex. A number of new and existing sites are suitable potential candidates for new nuclear units. In the IPSP, we propose to address two existing sites which are currently assessed to have the capacity to add new nuclear units, i.e., the Darlington and Bruce sites. Existing sites carry significant advantages, not least of which are shortened lead times to place a new nuclear unit in-service. The Pickering site is not currently being considered by the OPA for a future new nuclear unit given the space considerations. However, future utilization of this site for new or replacement nuclear units cannot be ruled out at this time. In addition to the Darlington and Bruce sites, we also propose to consider the suitability of the Nanticoke site as a potential location for new nuclear units.

The expected timeline for a new nuclear plant at an existing site is shown in Figure 4.8. In OPA's opinion, refurbishing existing units has some advantages over new build with respect to timeline, location and known operational costs. This belief stems from the expected length of the new build process, particularly since the choice of technology is still under consideration for both the Bruce and Darlington sites. Specific criteria related to siting of new nuclear facilities are provided by the Canadian Nuclear Safety Commission (CNSC).

Figure 4.8 – Typical Timeline for a New Nuclear Unit

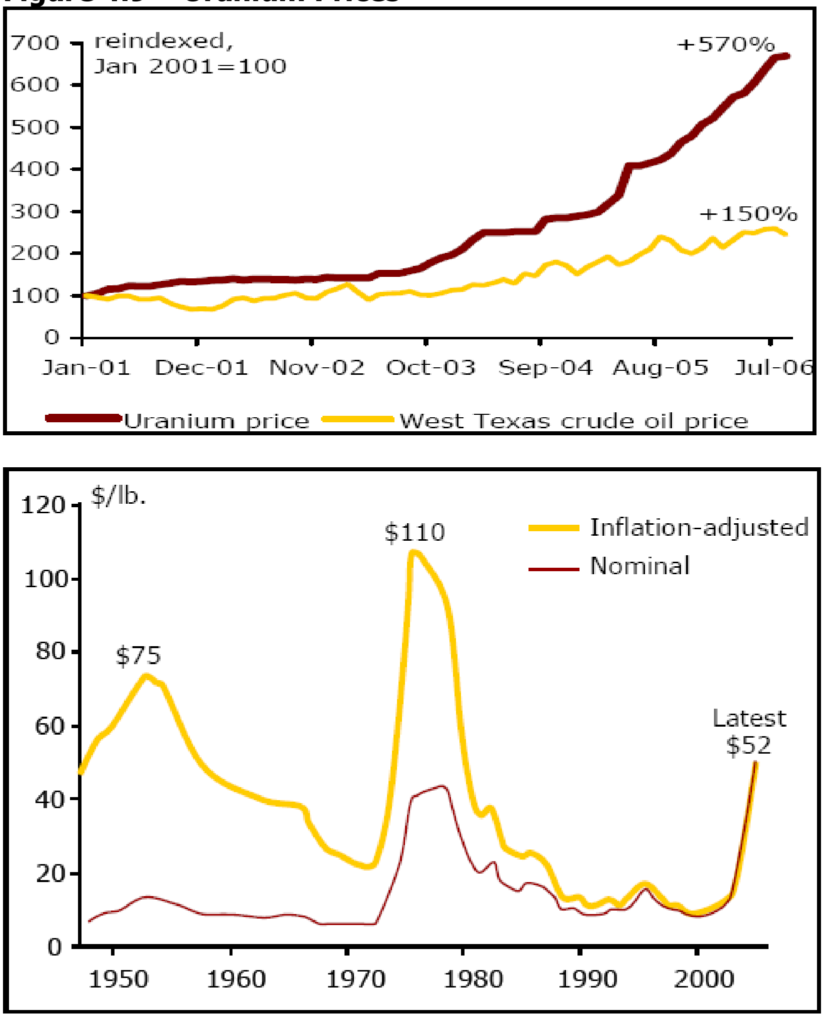


Source: OPG

Uranium Supply and Price Considerations

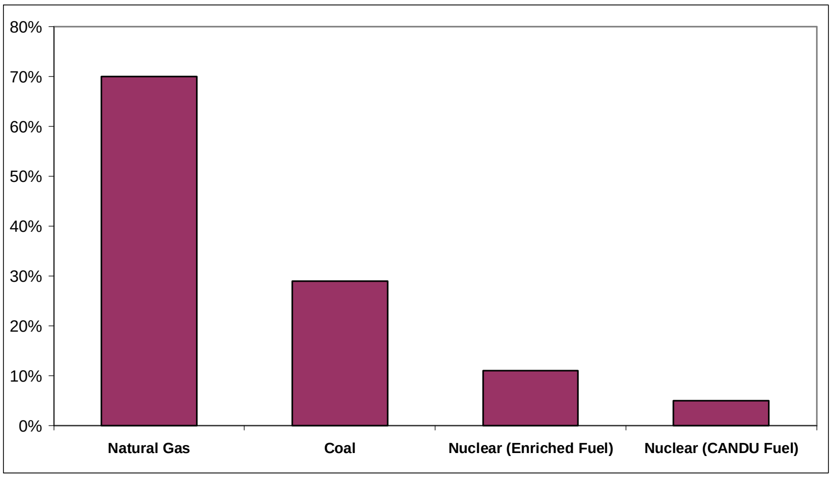
Figure 4.9 shows recent uranium price volatility in the context of industry experience over the last 50 years. While the current prices for uranium oxide at US $52/lb in July 2006 are high and volatile, real uranium prices are still well below the levels attained in the industry's previous boom cycles. In the mid-1950s, uranium prices had reached US $75/lb in today's dollars. Prices rose further in the 1970s, peaking at US $110/lb.

Figure 4.9 – Uranium Prices



Source: CIBC World Markets Monthly Indicators September 7, 2006.

Figure 4.10 – Comparison of Fuel Cost as a Proportion of Total Cost of Generation



Source: OPA (adapted from Energy Information Administration as cited in CIBC World Markets Indicators September 7, 2006)

The impacts on unit energy cost of nuclear from increases in uranium prices are generally smaller than comparable impacts on gas-fired electricity generation, as is shown in Figure 4.10. In Figure 4.10 the nuclear fuel cost of approximately 10 percent refers to enriched uranium fuel used, for example, in Pressurized Water Reactors (PWR). For CANDU reactors which use un-enriched or natural uranium fuel, the fuel cost represents less than 5 percent of the total unit energy cost. Over the last several years the cost of natural gas has effectively more than doubled and unlike nuclear power, fuel costs in gas-fired plants account for almost 70 percent of the unit energy cost.

4.1.8 Nuclear Waste Disposal and Decommissioning

The technologies for safe management of nuclear wastes are part of a worldwide development and are considered well established. The regulatory process for establishing the safety of the processes and methods for specific wastes arising from used fuel, decommissioning or refurbishment activities is licensed and approved by the Canadian Nuclear Safety Commission (CNSC) under federal jurisdiction. Similarly, the financial arrangements for managing future costs related to nuclear wastes are also well established. Here we provide a brief summary.

Nuclear Fuels Waste Disposal: Technology Considerations-The Federal Nuclear Fuel Waste Act, 2002, (NWFA) established the Nuclear Waste Management Organization (NMWO) to propose, select and implement an approach for the management of nuclear fuel waste. The NWMO has assessed three technical options specified by the Nuclear Waste Management Organization (NFWA) – Deep Geological Disposal; Storage at Nuclear Reactor Sites and Centralized Storage – and added Adaptive Phased Management.

The three methods specified by the NFWA are well understood and considered to be technically credible and viable. Storage technologies have been demonstrated for many years, and deep geological disposal has been studied for decades, leading to advanced scientific and technical understanding internationally. For additional details on the technical descriptions for each option, please see section 3.7 (Volume 3 of the *Supply Mix Advice Report*).

The study and advancement of technology for the transport, storage and permanent disposal of Canada's nuclear fuel waste has been underway for the past several decades. In 1978, the governments of Canada and Ontario established the Canadian Nuclear Fuel Waste Management Program, which had continued to research, develop and demonstrate interim and long-term disposal options.

Additionally, licensed interim storage methods have been designed and implemented by all of Canada's nuclear waste owners, who have also submitted conceptual long-term storage designs to the NWMO. Since 1978, Canada has spent over $800 million dollars on used fuel development. In recent years, OPG has managed the technology development program on behalf of the waste owners, ensuring that deep geological storage can be implemented, should the government decide to do so.

Table 4.1 – Projected Total Inventory of Used Nuclear Fuel

	Projected Total Used Fuel Inventory (number of bundles)	
Used Fuel Owner	**2001 Estimate**	**2004 Estimate**
Ontario Power Generation Inc.	3,274,431	3,274,412
Hydro-Quebec	132,838	180,000
NB Power Nuclear	119,500	180,000
Atomic Energy of Canada Limited	30,682	30,682
Total	3,557,451	3,665,094
Total (rounded)	3,600,000	3,700,000

Source: NFWMO *Nuclear Waste Management Organization: Choosing a Way Forward*, Nov. 2005.

In November 2005, the NWMO issued to the federal government "*Choosing a Way – The Future Management of Canada's Used Nuclear Fuel*". The report presents the results of work to date and recommends the Adaptive Phased Management approach, with the rationale that:

- it commits this generation of Canadians to take the first steps now to manage the used nuclear fuel we have created
- it employs the best available science and technology in pursuit of safety and security
- it provides for centralized containment and isolation of used nuclear fuel deep underground in suitable rock formations, with continuous monitoring and opportunity for retrievability, and,
- it allows sequential and collaborative decision making, providing the flexibility to adapt to experience and societal and technological change.

The covering letter concludes:

> *"We are confident that we have the necessary knowledge to begin to meet society's ethical obligations today and for the future. We are convinced that now is the time to act decisively."*

Decommissioning of Nuclear Units- The present concept for decommissioning of Ontario's nuclear power plants, is as follows:

- At technical or economic end-of-life, the units are to be placed in a safe-state (known in the industry as "dry lay-up". This involves defuelling the reactors, draining and drying the major systems and placing all systems in a safe state. This process would be expected to take place over a period of approximately two to three years following the shutdown.
- The units are then left in a safe state and monitored for approximately the next 27 years.
- Approximately 30 years after the units are shut down, dismantling of the station would begin and would be expected to take approximately 10 years for a four-unit CANDU station. Following this period, the site would be made available for reuse.

The funding of obligations for decommissioning and nuclear waste disposal is based on these reference concepts.

Nuclear Waste Management Costs- The Canadian philosophy for management of nuclear wastes is based on a key principle of the cost burden to be borne by the current generation. The goal is to avoid leaving a legacy to future generations of the cost of safe disposal. This is now established practice and mandated under the *Federal Nuclear Fuel Waste Act (Canada)* as stipulated by CNSC Regulatory Guide G-206. The entities who operate nuclear units annually contribute to segregated funds for the long-term management of used fuel and other radioactive wastes arising from the operation of their nuclear stations and for their eventual decommissioning. Contributions are made during the current station life, so that accumulated liabilities are fully funded by the end of current station life.

The methods and costs for managing the radioactive wastes which would arise from the refurbishment of nuclear units are also well understood and managed as part of ongoing support to nuclear operations. These wastes would include major components to be replaced in the refurbishment i.e., fuel channels, steam generators and feeder pipes, and other wastes such as contaminated clothing and tools. Under the terms of the Bruce Power lease, OPG is required to accept and manage the wastes from the refurbishment of the Bruce A units on a commercial basis. Thus, OPG will already have had experience in the management and the costs of refurbishment wastes from Bruce A by the time of the Pickering B refurbishment. Should the refurbishment of Pickering B, Bruce B and later Darlington proceed, OPG and Bruce Power will already have had experience in the management and the costs of refurbishment wastes, given that the Bruce A refurbishment is currently underway.

Based on the current decommissioning concepts, refurbishment of Ontario's nuclear plants and resulting life extension by approximately 30 years, would reduce the net present value of the decommissioning liability. This would apply in the case of a decision to refurbish Pickering B, Bruce B and/or Darlington. As well, OPG has indicated that because of the coordinated manner in which the Pickering A and Pickering B plants would be decommissioned, the net present value of the decommissioning liability of Pickering A would also decline should Pickering B be life-extended.

Similarly, based on the current concept for funding of long-term used fuel management in Ontario, the majority of the fixed costs for the long-term used fuel management program would have been provided for by the end of the current station life. Hence, the annual amounts to be set aside during the post-refurbishment lives would need to cover only incremental costs associated with the additional used fuel being generated. This funding would be expected to be significantly lower in real terms than current amounts.

The funding arrangements for managing nuclear wastes are summarized in Table 4.2. The present net value of OPG's future liability for nuclear waste has been calculated to be about $9 billion as at June 30, 2006. The corresponding net asset value of the segregated funds set aside by OPG was approximately $7.2 billion. These funds are held by an independent third party custodian and are segregated from OPG's other assets. Under the terms of the lease agreement with Bruce Power, OPG continues to be responsible for the nuclear fixed asset removal and nuclear waste management liabilities associated with the Bruce nuclear generating stations and these funds include provision for that. OPG continues to add over $400 million/year to the decommissioning and used fuel funds.

Table 4.2 – Nuclear Funding Arrangements (as at June 30, 2006)

Decommissioning Fund	$4,211 million
Used Fuel Fund	$2,985 million
Total (amortized cost)	$7,196 million

Source: OPG

For additional details, see "Provision for Managing Decommissioned Nuclear Generation and spent Fuel," Volume 3, section 3.7 of the *Supply Mix Advice Report* (Dec. 9, 2005).

Summary-Nuclear

The current operating nuclear units will reach end-of-life between 2013 and 2022. One of the major choices for Ontario to make is related to refurbishment of these units. Key considerations include confidence in the estimates for cost and schedules. While the ultimate decision on whether or not to refurbish nuclear units will rest with the owners and operators of these facilities, and will be based on their assessment of the business merits of refurbishment, for planning purposes, it is assumed that refurbishment of nuclear units will be a major component of the IPSP.

Nuclear Refurbishments: The OPA, working with existing licensed nuclear operators, has gained a better appreciation of the potential for refurbishment of nuclear units. Some important reasons for proposing that refurbished nuclear units should be included in the IPSP are:

- viable alternatives to fill a generation capacity gap within the tight timelines on the required scale (namely, 11,000 MW of replacement capacity) are not available. Use of gas-fired generation is not consistent with the "smart gas strategy" nor with the Ministerial directive
- proximity of existing licensed nuclear sites to Ontario's major load centres and availability of an adequate transmission infrastructure makes refurbishment attractive
- refurbishment provides a shorter lead-time option for nuclear capacity than new nuclear build
- refurbishment utilizes existing generation sites thereby minimizing the environmental "footprint"
- strong support in the host and surrounding communities for the continued operation of nuclear units at Pickering, Bruce and Darlington provides additional confidence in the proponent being able to complete the projects in a cost-effective manner
- lessons learned from recent Canadian and international experience related to refurbishment are being actively incorporated into design, engineering, planning, execution and management practices, giving further confidence in the ability of nuclear project proponents to manage cost and improve the reliability and performance of nuclear units
- methods and costs for managing nuclear wastes arising from refurbishment and future operation of nuclear units are well established and the existing funding provisions and arrangements, mandated through the *Federal Nuclear Fuel Waste Act (Canada)*, provide added confidence.

Including the refurbishment of the Pickering B nuclear units in the IPSP is supported. The continuation of preparations for the refurbishment, (based on a preliminary screening assessment of the refurbishment of Pickering B that has indicated that the economics of refurbishment are comparable to alternatives), would keep the option open, should the proponents find that the merits of the business case warrant its pursuit.

New Nuclear: Options to develop new nuclear units are being considered for existing licensed nuclear sites. The Environmental Assessment and safety regulatory processes are well established, providing guidance to the proponents and improving their ability to meet schedule and cost constraints.

- Bruce Power and OPG have applied for Site Preparation licenses for new nuclear plants at the Bruce and Darlington sites respectively. The process of obtaining all of the necessary approvals for new nuclear units is lengthy. The many approvals required fall mainly under the jurisdiction of the CNSC.
- The EA process combined with construction and commissioning lead times for the first unit result in project lead times which can range from 9 to 12 years. This means that there is a need to make decisions about new nuclear in a timely manner if the option of utilizing new nuclear to meet the expected supply gap is to be preserved.

- In the IPSP, the OPA will recommend that Environmental Assessments, Licensing activities and feasibility studies of new nuclear units be pursued in order to keep this option available for meeting the supply gap in the 2015 to 2025 time period.

4.2 Natural Gas and CHP

Natural Gas

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. To support effective implementation of this strategy, OPA is working to solidify its assumptions regarding natural gas supplies, price projections and infrastructure requirements in the IPSP.

The "smart gas strategy" regards gas as a supplemental resource. Whereas nuclear will provide baseload power and renewable energy will contribute additional grid-based energy, natural gas will balance the unpredictable availability of renewable supplies and meet peak load demands. Single-cycle gas turbines (SCGT) are well suited to provide peaking capacity, system reserve requirements and operational flexibility to compensate for intermittent renewable resources. In addressing more specific local area reliability issues, the size and location of natural gas resources are subject to fewer limitations than renewable energy and other forms of generation.

The smart gas strategy therefore creates two roles for gas SCGT facilities: (i) providing reliability to local areas where the generation is most cost-effective and needed, and (ii) contributing to capacity adequacy for the entire system.

This strategy still recognizes the substantial amount of combined cycle generation already committed for its ability to provide the high capacity factor intermediate and peaking generation that will, in effect, replace coal-fired generation in Ontario.

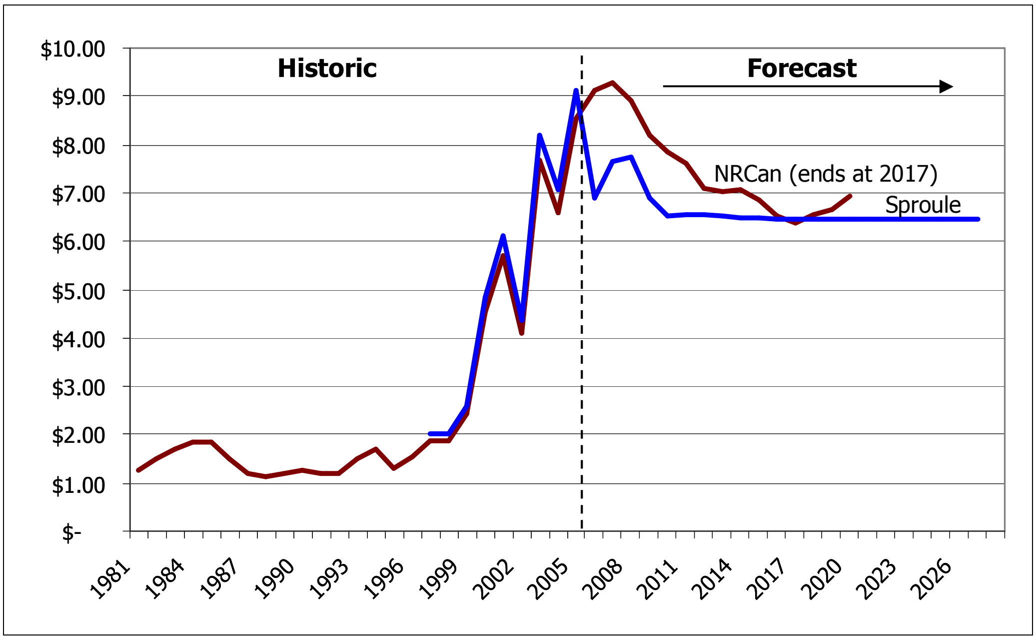
The IPSP will identify the amount and timing for gas generation required to meet both local area reliability concerns and to ensure an adequate supply of generation for the overall system. In some cases, specific sites will be identified. In other cases, sites will be flexible and therefore left undefined. This is further discussed in the Integration paper (discussion paper #7).

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. Recent short-lived price highs are attributed to hurricane activity in the Gulf Coast, and projected price decreases are expected due to crude oil price decreases. 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.

Future gas prices, in part, support a strategy that favours high efficiency and high-value applications for gas-fired power. OPA has reviewed two published forecasts of natural gas prices, including Sproule Associates Limited (Sproule), based in Calgary, Alberta, and that of

Natural Resources Canada (NRCan). These two forecasts are illustrated in Figure 4.11. The main difference between these forecasts is that, in real dollars, NRCan predicts a slower decline in gas prices in the period from 2007 to 2017, followed by a steady increase until 2020 (the end of NRCan's study period). Sproule, on the other hand, predicts a rapid decline in gas prices between 2006 and 2011, followed by steady prices thereafter.

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 .
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.
3. Future prices are discounted to 2006 Canadian dollars, and historic prices are presented in dollars of the day.
4. Sproule Associates Limited and OPA accept no responsibility for any inaccuracies within the forecast, and users are asked to recognize the high degree of uncertainty associated with forecasting oil and gas prices.
Sources: Sproule, NRCan

Combined Heat and Power (CHP)

In addition to SCGT, natural gas is well suited for combined heat and power (CHP) applications.[7] Accordingly, OPA is evaluating the potential for natural gas CHP in Ontario as an element of the "smart gas implementation strategy". An RFP for up to 1,000 MW of CHP resulted in 414 MW of contracts that are expected to be in-service between 2008 and 2010, the majority of which were natural gas fired (63 MW were by-product fuel fired). OPA has created an inventory of existing CHP facilities and will assess the potential for additional CHP projects based on the response to the RFP for CHP projects as well as other available information. This will provide a basis for estimating potential for CHP resources in the IPSP.

[7] Combined heat and power, CHP, is also referred to as cogeneration, the joint production of both electricity and usable heat.

CHP Potential in the Greater Golden Horseshoe

On June 16, 2006, the Government of Ontario released the Growth Plan for the Greater Golden Horseshoe, 2006. It was prepared under the *Places to Grow Act, 2005*. The map shown in Figure 4.12 depicts the area and centres impacted by this plan.

Figure 4.12 – Places to Grow: Ontario

Note: The information displayed on this map is not to scale, does not accurately reflect land-use and planning boundaries, and may be out of date. For more information on Greenbelt Area boundaries, consult the Greenbelt Plan 2005. The Province of Ontario assumes no responsibility or liability for any consequences of any use made of this map.
Source: Places to Grow Growth Plan for the Greater Golden Horseshoe, June 16, 2006 Ontario Growth Secretariat.

The Growth Plan identifies 25 urban growth centres, typically downtown or central business district areas, and sets out a number of policies, including a density target for each of these areas as identified in Table 4.3.

Table 4.3 – Density Targets for Urban Growth Areas

400 people & jobs combined per hectare	200 people & jobs combined per hectare	150 people & jobs combined per hectare
Downtown Toronto Etobicoke Centre North York Centre Scarborough Centre Yonge-Eglinton Centre	Downtown Brampton Downtown Burlington Downtown Hamilton Downtown Kitchener Uptown Waterloo Downtown Milton Markham Centre Mississauga City Centre Newmarket Centre Midtown Oakville Downtown Oshawa Downtown Pickering Richmond Hill/ Langstaff Gateway Vaughan Corporate Centre	Downtown Barrie Downtown Brantford Downtown Cambridge Downtown Guelph Downtown Peterborough Downtown St. Catharines

Source: Ministry of Public Infrastructure Renewal

The targets were developed to recognize the diversity among the 25 urban growth centres:

- the highest density target of 400 people and jobs per hectare applies to urban growth centres in the City of Toronto, which already has a large population and existing high frequency subway service in place
- a density target of 200 people and jobs per hectare applies to urban growth centres in large or mid-size cities in the Greater Toronto Area (GTA) and Waterloo Region, where higher-order transit is in place or planned
- outside the GTA, where urban growth centres are in smaller mid-size cities, and transit linkages to the GTA are more limited, the density target of 150 people and jobs per hectare is applied.

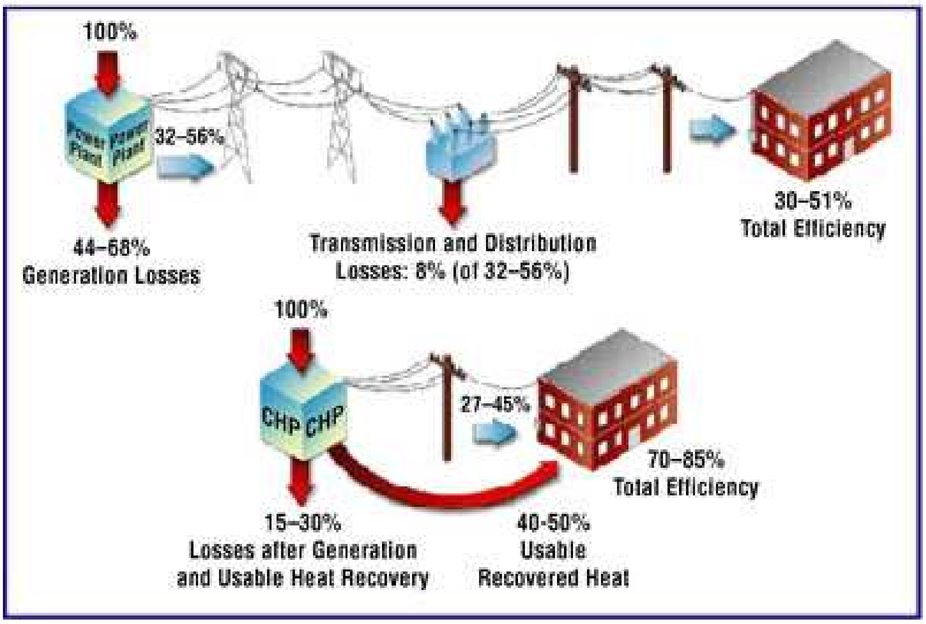
The intensification plan is a positive feature for the future development of the power system. It contributes to the cost-effective achievement of conservation targets and promoting the economic feasibility of cogeneration facilities where density of population makes it possible. Municipalities will develop and implement official plan policies and other strategies in support of:

- energy conservation for municipally-owned facilities
- identification of opportunities for alternative energy generation and distribution
- energy demand management to reduce energy consumption
- land-use patterns and urban design standards that encourage and support energy-efficient buildings and opportunities for cogeneration.

Aside from the possible conservation effects on the load requirements of the higher density development required by the guide, the government's strategy for intensification provides improved opportunities for cogeneration/CHP development. The shorter access distances between a cogeneration facility and customers for heat and power from a cogeneration facility, akin to the experience in Europe, could be a powerful incentive for economic CHP. Figure 4.13 shows the potential gains in efficiency from CHP where distances are short and proximity to end-use customers enable recovery of heat for sale.

However, the ability of CHP to be brought into existing industrial facilities may be limited by several factors that impede the viability of economic CHP development. Technical factors such as available land, emissions, noise, interfacing with existing infrastructure, optimisation of electrical/thermal requirements and redundancy requirements may all encumber cost-effective CHP development. Further challenges arise when considering the host facility's business requirements. CHP may require significant capital on behalf of the host and the host may consider that any available capital is best directed at the host's core business and not on longer horizon energy sustainability efforts. Furthermore, CHP is a specialist process which may not necessarily be within the expertise or the focus of the host. All these factors may contribute to viable CHP development targets being less than forecasted using broad-based industrial density indexes.

Figure 4.13 – Illustration of Improved Efficiency of CHP vs Centralized Generation



Source: U.S. Department of Energy

It is possible for CHP installations to be highly efficient. However, high thermal efficiency depends on the use of all of the heat all of the time, which is only possible if thermal and electrical production cycles are identical. In addition, high thermal efficiency is only achieved if the thermal host requires low quality heat.

OPA will monitor developments as well as enabling technologies and assess the consequences for fuel mix of electricity sources. The requirements for transmission and distribution systems upgrades to facilitate timely cogeneration/CHP developments will also be monitored on a periodic basis.

4.3 Storage

The potential system benefits of energy storage in Ontario have been considered. Storage can be provided in several ways including: (i) pumped generation storage (PGS), (ii) storage at a neighbouring utilities' system, and (iii) new emerging storage technologies such as superconducting magnetic energy storage (SMES), flow batteries or compressed air energy storage.

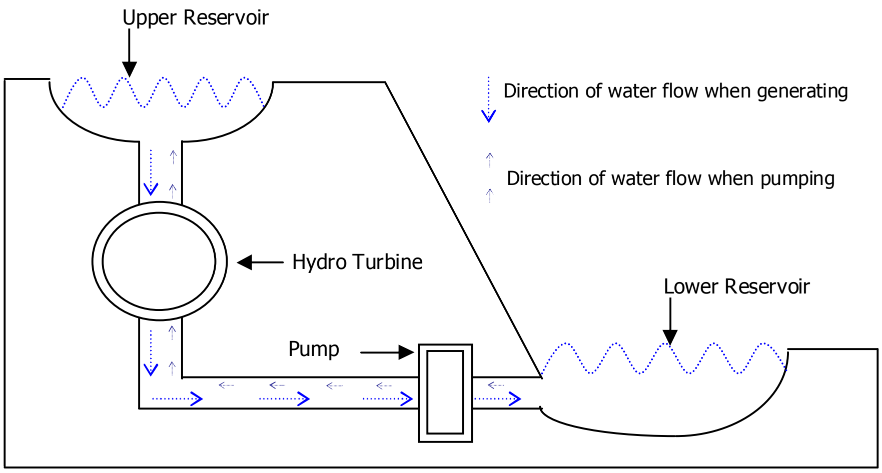
4.3.1 Pumped Generation Storage

Pumped generation storage is a potentially valuable resource to complement intermittent resources such as wind power, particularly as wind becomes a more significant component of the supply mix in Ontario in the future. Its possible uses include mitigating wind output variability, as well as absorbing off-peak or excess wind output for use later during higher-value periods. More specifically, pumped storage can assist in meeting load-following and peaking capability as well as provide ancillary services such as regulation, operating reserve, and black start capability.

The Concept

In a pumped storage system, water is released by gravity from an upper reservoir to a lower reservoir. Along the way, it is passed through a hydro-turbine to produce electricity. The water is typically pumped back into the upper reservoir during off-peak periods such as overnight or during weekends when electricity rates are lower. Production on the other hand typically occurs during on-peak periods when the rates are higher. Figure 4.14 illustrates the pumped storage concept.

Figure 4.14 – Schematic of Pumped Storage Concept



Source: OPA

Pumped storage is a mature and widely used technology, with total global pumped storage capacity estimated to be 83,000 MW.[8]

Preliminary Economic and System Analysis

The potential benefits of pumped storage were assessed by comparing the economic impacts of adding an increment of pumped storage to Ontario's power system in place of an equivalent amount of natural gas-fired generation or conventional hydroelectric generation. The results of very preliminary economic analysis suggest that pumped generation storage is competitive compared to simple cycle gas-fuelled generation, but is generally less competitive than comparable new hydroelectric plants. The results also indicate that the economics of pumped generation storage are significantly enhanced provided pumping energy costs are low ($10/MWh or less) and capital costs are of the order of $1,000/kW or less. OPA intends to perform further analysis to confirm the preliminary results.

Potential PGS Sites

OPA has reviewed the following potential PGS sites for which pre-feasibility studies have been conducted in the past by consultants. This does not preclude the identification of other sites which may also have potential for pumped generation storage. The Ministry of Natural Resources (MNR) has recently released two of these sites (Steep Rock Iron Mines and Fourbass Lake) under its Site Release Program for pumped storage projects.

[8] Australian Government. Department of the Environment and Heritage, Australian Greenhouse Office. Advanced Electricity Storage Technologies Programme - Energy Storage Technologies: a Review Paper. December 2005.

Marmora

Located between Peterborough and Marmora in southern Ontario, this site makes use of an abandoned open-pit mine. This existing pit (currently filled with water and debris), would form the lower reservoir. An upper reservoir would have to be built on the hill formed by the tailings and excavated earth located near the edge of the pit. The installation would be spring-fed to compensate for evaporation and other water losses.

The potential capacity of a PGS located at the Marmora site is estimated to be about 200 MW (generation). Assuming an ACF of 18 percent (corresponding to operation at six hours/day, five days a week), the PGS could contribute about 320 GWh of energy production to peak system load.[9]

Possible in-service dates for a PGS at Marmora are considered to be practical in the 2012-2015 time period.

Fourbass Lake

This site is in northeastern Ontario, just off the Matabitchuan River. Development of this site has been studied in the past, but the economic analysis did not warrant further consideration at the time. Recently, the site has attracted renewed interest and submissions have been made to the Ministry of Natural Resources by private proponents.

Development of a 400 MW PGS is technically feasible. At 24 percent ACF, the PGS could generate about 830 GWh of energy during peak hours. Correspondingly, about 1,100 GWh of inexpensive off-peak pumping energy is required to enable that production. The location of this site is attractive because of its location in the eastern part of the province (northern Ottawa Valley) and with readily accessible transmission.

In--service date for this station has been nominally assumed at 2019.

Steep Rock Iron Mines

Located near Atikokan, Ontario, the Steep Rock Iron Mines site is the largest of the three sites considered. It would feed into the western end of the East-West transmission tie line, which has been known to be a serious bottleneck, particularly at times of peak demand.

As in the Marmora development, this project would make use of an existing mine site, now out of production. In this case, however, the surface pit would likely be the upper reservoir of the PGS, while the lower reservoir would be created from existing and new underground caverns.

The Steep Rock Iron Mines site has a nominal capacity of 500 MW. Pending further studies, the actual capacity could be higher. At 500 MW capacity and 24 percent ACF, a PGS would supply

[9] Sizing a PGS does not follow the same rules as a conventional hydro plant. While its capacity still depends on head and its energy production capability depends on the water it has at its disposal, there exists considerable flexibility in determining what the 'optimum' capacity would be for a given installation. Power system factors such as peak sustainability, demand and market price differentials between off-peak and on-peak periods, etc., may ultimately supersede physical site characteristics for arriving at a 'best overall' capacity.

1,040 GWh of energy during peak hours. Correspondingly, about 1,350 GWh of off-peak pumping energy would be required to fill up the upper reservoir.

In-service date for this installation has nominally been assumed at 2020.

Summary: Pumped Generation Storage

At this time OPA does not consider there to be a need in the near term for pumped generation storage or for alternatives to pumped generation storage. This assessment will be reviewed on a periodic basis as supply mix and system conditions change.

Options and competing technologies to pumped generation storage to be considered in the future will include functional imports from nearby utilities that have storage capacity or implementation of some of the (emerging) storage technologies (e.g., flow batteries).

4.3.2 Energy Storage and Neighbouring Utilities

Existing interconnections between Ontario and adjacent states and provinces accommodate bulk interregional power flows and help to accommodate Ontario's own load requirements. Ontario's transmission system connections with neighbouring provinces and states make it the most highly interconnected system in Canada. With its geographical advantage, Ontario links low-cost, storable Canadian hydropower sources with U.S. markets.

Electricity markets tend to be imperfectly correlated and can be highly volatile. With enabling transmission access, generators and loads may be able to sell and buy power utilizing the storage capacity of their systems. For example, hydroelectric generators with large reservoirs (such as those in Manitoba and particularly Quebec) can perform temporal arbitrage between markets. Michigan may also be able to provide storage capability. These generators can purchase electricity from adjacent markets to meet their domestic off-peak needs and thus save their hydroelectric capacity for sale during high-price on-peak hours. Thus, a system of a neighbouring utility can act as a "mega-peaker" storage system as long as there is transmission capacity that enables this type of arbitrage.

Ontario's system is strategically located between large Canadian hydro resources (Manitoba, Quebec and Newfoundland) and a U.S. market to the south that is largely carbon based (coal or natural gas). Ontario's transmission system is an important enabler that can play a key role in providing clean storable power to this large regional market. In doing so, it can help industry and governments meet stricter environmental quality objectives. The reductions in SO_x, NO_x and particulate emissions, by better utilizing system capacity through storage, has direct positive benefits for human health. Reductions in CO_2 emissions will help Ontario meet targets.

Hydro power is particularly well-suited to meet the peak needs of this large regional market because, unlike other electricity sources, it can be effectively stored or "banked" in reservoirs. Ontario's large baseload nuclear capacity, which must run constantly, complements hydro capacity in neighbouring provinces since nuclear-based power can be used to meet off-peak needs in these provinces, increasing the potential storage of hydro power for peak uses. The net result is potentially the replacement of large amounts of coal-fired peaking capacity throughout the Great Lakes airshed with cleaner nuclear and hydro power.

Development of the 1,250 MW HQ interconnection between Ontario and Quebec would accommodate bulk interregional power flows and help to reliably serve Ontario's native load.

In addition to the technical potential and benefits discussed above, it should be recognized that there are differences in electricity market structure and pricing rules between the various interconnected jurisdictions. These differences can result in inequitable allocations of costs and benefits which could affect progress in the near future.

4.3.3 Emerging Storage Technologies

Recent developments in advanced energy storage technology and results from a number of large-scale demonstration projects indicate new opportunities for energy storage in grid stabilization, grid operations support and load shifting applications. Energy storage will provide many future benefits to the power system. It could lead to a more efficient electrical system that costs less to operate and that is more reliable in the event of disruptions. In simple terms, energy storage technologies remove some of the uncertainties and enhance the capability of other assets by acting as a damper to the interconnected network. Energy storage helps match demand and supply by storing energy when demand and cost to produce electricity are low and reintroducing the same energy into the system when demand and prices are high.

Use of stored energy for applications in the support and optimization of transmission and distribution systems has been somewhat limited primarily due to a lack of cost-effective technologies and sufficient practical experience to perform comparative evaluations of the benefits. Described below are the current status and potential capabilities of innovative technologies that will begin to find niche applications in the power system over the plan period.[10] Several technologies are under development and currently used in a number of specialist applications. They are used to improve power quality by correcting voltage sags, flicker, surges, or to correct for frequency imbalances. Storage devices are also used as uninterruptible power supplies (UPS), supplying electricity during short utility outages. Because these energy devices are often located at or near the point of use, they are usually considered as distributed resources.

The following technologies are discussed in this section:

- Battery storage
- Flow batteries
- Superconducting magnetic energy storage (SMES)
- Super-capacitors
- Compressed air energy storage (CAES)
- Flywheels

[10] Source: http://www.energy.ca.gov/distgen/equipment/energy_storage/energy_storage.html

- Thermal energy storage.

Applications for energy storage plants within the electricity infrastructure depend on the storage plant capacity and discharge time capacity. There are many possible applications including system stability and VAR support, power quality regulation, frequency regulation, load-following, spinning reserve, and load-levelling.

Battery Storage

Utilities typically use batteries to provide an uninterruptible supply of electricity to power substation switchgear and to start backup power systems. However, there is an interest to go beyond these applications by performing load-levelling and peak shaving with battery systems that can store and dispatch power over a period of many hours. Batteries also increase power quality and reliability for residential, commercial, and industrial customers by providing backup and ride-through during power outages.

The standard battery used in energy storage applications is the lead-acid battery. A lead-acid battery reaction is reversible, allowing the battery to be reused. There are also some advanced sodium/sulfur, zinc/bromide, and lithium/air batteries that are nearing commercial readiness and offer promise for future utility application.

Battery storage systems typically cost $1,000 per kW. The lead-acid battery industry has a goal to reduce this cost to $400 per kW to improve on the relative low performance to cost ratio of the battery energy storage systems.[11]

Flow Batteries

Flow batteries are a promising technology capable of providing comparable levels of large-scale energy storage options to pumped hydro storage, compressed air energy storage systems and lead-acid batteries.

Flow batteries are a new type of energy storage different from conventional rechargeable batteries in one significant way: the power and energy ratings of a flow battery are independent of each other. This is made possible by the separation of the electrolyte and the battery stack. In a flow battery, liquid electrolytes are stored in tanks external to the battery cells and circulated between tanks and electrodes within the cells by pumps. The cells in the battery stack can be connected in series or parallel to meet distinct voltage and current requirements. Power capacity is a function of the surface area of the cells in the battery stack and the storage capacity can be increased at little additional cost by increasing the size of the tanks holding the electrolytes.

[11] R. Baxter, "Revisiting Energy Storage,' Energy Markets, (November 2002).

Flow batteries offer long life cycle and rapid response to load changes suitable for applications where a large capacity of stored energy is required (e.g. load levelling or peak shaving). There are four leading technology paths for development of flow batteries:

- polysulfide bromide (PSB)
- vanadium redox (VRB)
- zinc bromine ($ZnBr_2$), and
- hydrogen bromide (HBr).

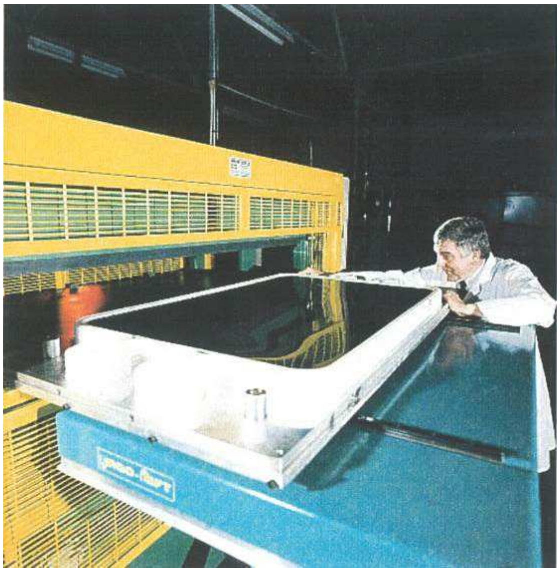
Advantages of a flow battery include:

- separate power and energy ratings, power being a function of the number of battery cells and energy a function of the volume of electrolyte
- easy thermal management so that life and performance can be maximized
- amenable to the use of bipolar cell-stack arrangements to maximize costs for high voltage, multi-batteries.

Cost comparisons amongst the flow batteries are complicated by the separate power and energy functions of these batteries. The power capacity costs for flow batteries are in the $1,500-$5,000/kW range with manufacturers targeting to reduce capacity cost to $1,000/kW or lower.

Figure 4.15 – Flow Batteries

ZBB 400 kWh System at Lum, Michigan



Regenesys Sub-Stack Assembly

Source: ZBB Power Engineering

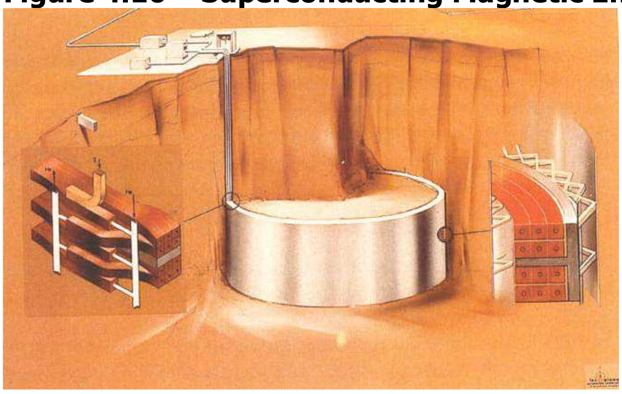
Superconducting Magnetic Energy Storage (SMES)

Superconducting magnetic energy storage systems store energy in the field of a large magnetic coil with direct current flowing. This energy can be converted back to alternating current (AC) electric current as needed. Low temperature SMES cooled by liquid helium is commercially available. High temperature SMES cooled by liquid nitrogen is still in the development stage and may become a viable commercial energy storage source in the future.

A magnetic field is created by circulating a direct current in a closed coil of superconducting wire. The path of the coil circulating current can be opened with a solid state switch which is modulated on and off. Due to the high inductance of the coil, when the switch is off (open), the magnetic coil behaves as a current source and will force current into the capacitor which will charge to some voltage level. Proper modulation of the solid-state switch can hold the voltage across the capacitor within the proper operating range of the inverter. An inverter converts the DC voltage into AC power. SMES systems are large and generally used for short durations, such as utility switching events.

SMES was originally considered for load-levelling but was subsequently implemented on electric power systems for pulsed-power and system-stability applications. Figure 4.16 shows a system rated at 500 MW and stores sufficient energy to deliver this power for six to eight hours. The coil is about 1,000 metres in diameter and is located at sufficient depth below grade for the surrounding soil to support the magnetic loads from the coil. SMES units have been proposed over a wide range of power (1 to 1,000 MW) and energy storage ratings (0.3 kWh to 1,000 MWh). Independent of size, all SMES systems include a superconducting coil, a refrigerator, a power conversion system and a control system.

Figure 4.16 – Superconducting Magnetic Energy Storage Systems (SMES)



Large-Scale SMES System

Trailer-mounted D-SMES Unit (3MW and up to 16MVA capacities)

Source: American Superconductor Inc.

Super-capacitors

Super-capacitors (also known as ultra-capacitors) are DC energy sources and must be interfaced to the electric grid with a static power conditioner, providing 60-Hz output. A super-capacitor provides power during short duration interruptions and voltage sags. By combining a super-capacitor with a battery-based uninterruptible power supply system, the life of the batteries can be extended. The batteries provide power only during the longer interruptions, reducing the cycling duty on the battery.

Small super-capacitors are commercially available to extend battery life in electronic equipment, but large super-capacitors still in development may soon become a viable component of the energy storage field.

Compressed Air Energy Storage (CAES)

Compressed air energy storage uses pressurized air as the energy storage medium. An electric motor-driven compressor is used to pressurize the storage reservoir using off-peak energy and air is released from the reservoir through a turbine during on-peak hours to produce energy. The turbine is essentially a modified turbine that can also be fired with natural gas or distillate fuel.

Ideal locations for large compressed air energy storage reservoirs are aquifers, conventional mines in hard rock, and hydraulically mined salt caverns. Air can be stored in pressurized tanks for small systems. For power plants with energy storage in excess of approximately 100 MWh or five hours of storage, the compressed air is most economically stored in underground salt caverns or favourable geological media.

Compressed air energy storage facilities are capable of storage that can generate above 100 MW of power and store large amounts of energy. Currently, manufacturers can develop facilities ranging from 5 MW to 350 MW. Cold start-up times have been reduced to seconds with modern plants and are a preferred spinning reserve option.[12]

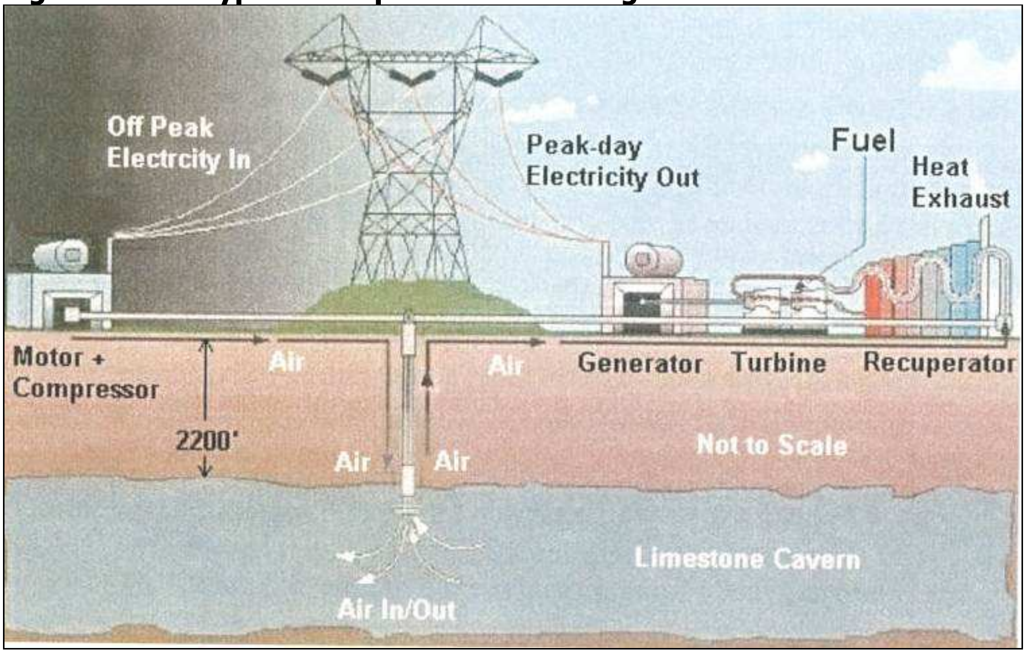
The first and longest operating CAES facility in the world is near Huntorf, Germany. The 290 MW plant functions primarily for cyclic duty, ramping duty, and as a hot spinning reserve for industrial customers in northwest Germany. Recently, the plant has been successfully used for levelling the variable power from numerous wind turbine generators in Germany. The only CAES facility in the U.S. is a 110 MW plant near McIntosh, Alabama that performs a wide range of operating functions including load management, ramping duty, generation of peak power, synchronous condenser duty and spinning reserve duty.

Capital costs of CAES facilities mainly depend on the type of underground storage and geology and can vary from $700-$1,200/kW. A promising CAES concept is the buried pipe subsurface (SSCAES) that allows projects to be developed independent of local geology.[13] An SSCAES facility has a lower storage capability (2-15 MW, $600/kW for six hour storage) compared to the capability of traditional plants.

[12] D.T. Bradshaw, *"Pumped Hydroelectric Power and Compressed Air Energy Storage"*, IEEE PES Meeting on Energy Storage (2000).

[13] D.T. Bradshaw, *"Evaluation of Subsurface Compressed Air Energy Storage (SSCAES)"*, Energy Storage Association, Pleasanton, CA (April 2000).

Figure 4.17 – Typical Compressed Air Storage Plant



Typical Compressed Air Energy Storage Plant
Source: Norton Energy Storage LLC

Flywheels

A flywheel is an electromechanical device that couples a motor generator with a rotating mass to store energy for short durations. Conventional flywheels are "charged" and "discharged" via an integral motor/generator. The motor/generator draws power provided by the grid to spin the rotor of the flywheel. During a power outage, voltage sag, or other disturbance, the motor/generator provides power. The kinetic energy stored in the rotor is transformed to direct current (DC) electric energy by the generator, and the energy is delivered at a constant frequency and voltage through an inverter and a control system.

Traditional flywheel rotors are usually constructed of steel and are limited to a spin rate of a few thousand revolutions per minute (RPM). Advanced flywheels, constructed from carbon fibre materials and magnetic bearings, can spin in vacuum at speeds up to 40,000 to 60,000 RPM. The flywheel provides power during the period between the loss of utility-supplied-power and either the return of utility power or the start of a sufficient backup power system (i.e., diesel generator). Flywheels provide 1-30 seconds of ride-through time, and backup generators are typically online within 5-20 seconds.

Commercialization efforts continue. There is a growing array of new flywheel products emerging that caters to a number of applications including voltage regulation and stabilization in substations and wind generation stabilization. Primarily, the products are targeted for the power quality market and targeted as environmentally safe, reliable, modular and high-life cycle alternatives to lead-acid batteries for uninterruptible power supplies (UPS) and power conditioning equipment for critical or protected loads. Flywheels are used extensively in commercial and industrial applications as ride through systems for critical loads. Large flywheel demonstration systems have attracted some utility attention. Flywheel systems are capable of providing cost effective solutions for specific applications in the $750 to $1,000 per kW range.

Figure 4.18 – Flywheel Installation at NYCT

Flywheel Installation at NYCT Bay Equalizer Location

10 100 kW Units in New Building

Source: NYCT

Thermal Energy Storage

Below the frost line (one to two metres underground), the ground temperature remains relatively constant year round. This temperature stability can be utilized for pumping heat energy from the subsurface into buildings in winter, or from buildings into the subsurface during the summer. In other words, the ground below the frost line can supply heat in winter and act as a heat sink in the summer. This geothermal heat can displace electric heating in winter or air-conditioning loads in summer. In certain applications, these systems can store thermal energy from one season to the next.

The University of Ontario Institute of Technology (UOIT) has installed one of North America's largest geothermal storage systems that, in addition to reducing the University's energy requirements, is being used for research and education in thermal energy storage. The system consists of 384 boreholes drilled 213 metres deep, which contain an interconnected network of polyethylene tubing that circulate a glycol solution. During the winter, the circulating fluid collects heat from the earth and transports it into the buildings. In the summer, the system reverses and carries heat from the buildings into the ground. The system at UOIT is illustrated in Figure 4.19.

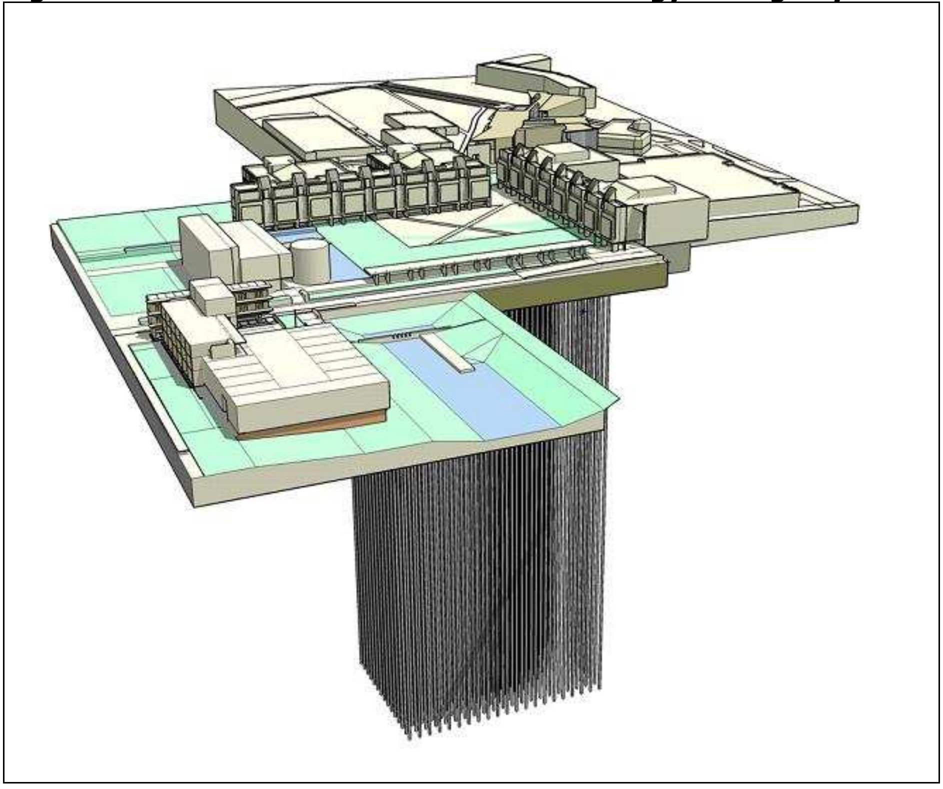
It should be noted that geothermal energy storage and heat exchange systems can be installed in a variety of sizes, scales and locations. Although the capital cost is high, OPA recognizes that the capacity and expertise to install effective geothermal energy systems is building in Ontario.

Geothermal energy for direct use relies on heat derived from a geothermal reservoir. A geothermal reservoir is formed when hot water and steam move upward from the Earth's interior towards its surface and become trapped in the permeable rock below. These reservoirs are sources of geothermal energy that have the potential to be tapped for electricity generation or direct use of heat.

The key to geothermal development lies in the magnitude of accessible moderate and high temperature geothermal resources suitable for electricity production. When geothermal reservoir fluid temperature exceeds 175°C, flash steam technology is usually employed. When the geothermal fluid temperature is below 175°C, binary cycle technology is usually employed.

The technology is commercially mature and overall, geothermal power systems are attractive from an environmental profile. Cost compared to other renewable resources such as wind is still high. Uncertainty surrounding the level of accessible geothermal resources remains a key barrier to its development.

Figure 4.19 – Illustration of Geothermal Energy Storage System



5. Promising Technologies and Their Potential

5.1 Distributed Generation Technologies

As part of meeting the supply challenge through to 2027, OPA is committed to playing an active part in facilitating the development of renewable and distributed sources of generation in Ontario. The Standard Offer Program is designed to stimulate the development of small-scale renewable energy opportunities. Fixed-term standard offer contracts will be available to renewable projects under 10 MW subject to transmission capacity limitations. This program will also include small gas-fired generation, in accordance with the Minister's request.[14]

Future development and effective implementation of distributed and renewable energy generation resources will require close coordination and integration with both the transmission and distribution systems. The IPSP will monitor these aspects to ensure distributed generation resources continue to play a positive role in meeting Ontario's needs. Distributed energy sources by type include solar, wind, bioenergy, fuel cells and CHP on a smaller scale fuelled mainly by natural gas or diesel and oil. The enabling distributed generation technologies with their attributes and potential are briefly described under two broad categories: (i) solar photovoltaics and (ii) micro-power enabling technologies.

Solar Power

There are two different solar power technologies: solar photovoltaic (PV) modules and solar thermal systems. Solar cells, also known as photovoltaics, use semiconductor materials to convert sunlight into electric current directly without an intermediate heating stage. Solar thermal electric technologies utilize primarily the direct component of total solar radiation. These technologies involve solar collectors, energy storage devices and conversion equipment to transfer the sun's energy to a working fluid which in turn drives a heat engine to produce electricity. Solar thermal systems can be used for generating power on a large scale similar to conventional generating units.[15] In this section, we focus on the potential for solar power as a distributed energy generation technology for use at the customer site.

Photovoltaic technology is well established and widely used throughout the world with an existing installed capacity of 5,000 MW worldwide. Solar cells can be made from a range of materials, from the traditional multi-crystalline silicon wafers that still dominate the market to

[14] See the OPA website for more details on the program. This also includes renewable energy - wind, small hydroelectric, solar photovoltaic and some biomass, as defined by the RES II RFP. http://www.powerauthority.on.ca/Page.asp?PageID=924&SiteNodeID=161

[15] See Scientific American, September 2006 issue that describes a Stirling Engine Solar Concentrator system. Two large solar thermal plants are being planned in southern California, a 500-MW plant to be constructed in the Mojave Desert stretching across 4,500 acres with 20,000 curved dish mirrors and a 300 MW, 12,000 dish plant in the Imperial Valley.

thin-film silicon cells and devices composed of plastic or organic semiconductors. Thin-film photovoltaics are cheaper to produce than crystalline silicon cells but are also less efficient at turning light into power. Technology improvements, cost improvements and favourable policies have resulted in significant increases in the annual production of photovoltaics over the past decade and this trend is expected to continue.

Solar photovoltaics are particularly easy to use because they can be installed in so many places - on the roofs or walls of homes and office buildings. For example, California has joined Japan and Germany in leading a global push for solar installations; the "Million Solar Roof" commitment is intended to create 3,000 MW of new generating capacity in California by 2018. The cells manufactured last year added 1,727 MW to worldwide generating capacity, with 833 MW made in Japan, 353 MW in Germany and 153 MW in the U.S.

Photovoltaic systems suitable for residential use can be purchased from local retailers in many parts of North America, Europe and elsewhere. Applications of photovoltaic technology include installations which power homes, telecommunications equipment, lighthouses, remote monitoring stations, irrigation systems and cottages. Photovoltaic systems may or may not be connected to an electrical grid system; they can be operated as "stand-alone" systems.

Figure 5.1 – Illustration of a Residential PV System

Source: Scientific American (September, 2006)

In Ontario's climate, with a relatively low proportion of direct sunlight, flat plate photovoltaic arrays are appropriate. The most cost-effective applications of solar photovoltaic technologies will be in the remote north where the cost of conventional electricity is very high. Utility interactive photovoltaic systems are expected to be smaller decentralized installations as opposed to large stations, since sunlight is a dispersed source of energy and photovoltaic systems are modular. Modularity, however, enables the addition of small blocks of capacity to match growth in demand and dispersal of the units helps to reduce transmission costs.

In Ontario, generation from solar is most likely to come from dispersed photovoltaic power sources with the arrays incorporated into the building structure; roof-tile and picture-window modules. An appropriate use would be to offset some of the air-conditioning load and reduce peak demand on hot summer days.

Cost is still the critical factor limiting application of photovoltaics. The estimated cost of energy ranges from 25 to 30 cents U.S. per kWh.[16] The Standard Offer Program provides 42 cents per kWh to a customer for 20 years. It is expected that this initiative will spur growth of solar photovoltaic installations in Ontario. For planning purposes, we assess that solar has a near-term potential of 50 MW rising to 100 MW towards the end of the planning period.

Micro-Power

Distributed resources generally described as micro-power comprise the following:

- micro-turbines (20-100 kW)
- wind power as micro generation (small projects with outputs from 50 kW to 10 MW)
- biogas and biomass (landfill sites, agricultural and livestock operations, wood forest residues, wastewater treatment facilities:1-10 MW)
- CHP including micro-CHP (residential 1 kW-25 kW Stirling engines), and CHP combined with seasonal storage
- fuel cells (50 kW to 1 MW)
- natural gas reciprocating engines (30 kW- 3 MW) and dual fuel reciprocating engines (90 kW- 2 MW)
- gas and diesel fired combustion turbines (approx 1 MW range)
- quasiturbines.

In the following sections, several of these resources are discussed further.

Micro-turbines

Micro-turbines operate on the same basic thermodynamic principles as the gas turbine. Unlike gas turbines, which have been adapted from jet engines for power generation, micro-turbines for power generation have been adapted from turbocharger technology originally used on reciprocating engines. Micro-turbines are generally much smaller than gas turbines and are scaled down to a level that makes them suitable for small buildings and even households. Thus they are generally measured in the tens to hundreds of kilowatts, rather than megawatts.

Micro-turbines have fewer moving parts than reciprocating engines, giving them the potential for longer lives with reduced maintenance. Micro-turbine technologies also offer lower emissions than comparably sized reciprocating engines. Furthermore, their fuel flexibility allows a variety of potential applications, ranging from distributed generation and cogeneration

[16] Scientific American, September 2006

when using natural gas, to transportation applications when using gasoline or diesel fuel. Several manufacturers now offer or are developing micro-turbines.

A number of organizations[17] have estimated micro-turbine costs and made projections for future decreases. Installed capacity costs are in the $1,500/kW-$1,750/kW range. The unit energy costs are in the 9 to 12 cents/kWh range. As is the case with several of the technologies discussed, there is an expectation that mature market prices will decline as production volumes increase.

Fuel Cells

Fuel cells use chemical reactions rather than combustion to produce both electricity and thermal energy. Because there is no combustion, emissions are very low. In areas with very strict requirements on air emissions, fuel cells may be the most viable distributed generation option. Fuel cells have generated considerable interest, but real-world experience remains limited. Fuel cell developers are experimenting with different technologies and a variety of packaging and distribution arrangements. Although most residential systems are based on proton exchange membrane (PEM) technology, units based on solid oxide fuel cells (SOFC) are also being developed.

Fuel cells are currently much more expensive than reciprocating engines or micro-turbines. But because fuel cells have virtually no emissions, they will likely continue to garner considerable investment in their development. The next several years will be important as manufacturers try to make good on promises to provide commercially viable products.

Initial capital costs are high. The cost estimates are in the range of $5,000-7,500/kW. Their costs have actually risen over the recent past. With modest cost reductions over the next five years, the expectation is that they would provide electricity service at a unit energy cost in the 20-25 cents/kWh range.

Stirling Engines

The defining characteristic of Stirling engines is that they are powered by an external heat source. This provides numerous advantages over internal combustion engines, including the fact that they can utilize virtually any energy source (or several different energy sources) operating at more than 400°F. This energy can come from such sources as traditional fossil fuels, sawdust, solar energy, or heat recovered from another thermal process.

Stirling engines have been in use for almost 200 years, but this has not translated into dominance as an engine design. Development of temperature resistant materials and long-life seals is expected to improve their performance. Stirling engines appear to have very low maintenance requirements, and because they offer very high temperature thermal-energy recovery, they are ideal for cogeneration and absorption-based cooling systems.

Stirling engines are being developed around the world. Early commercial models are available in limited quantities in Europe and Japan. Within the next few years, developers in Europe,

[17] Gas Research Institute (March 1999), Office of Industrial Technology, U.S. DOE (Jan 2000), Deutsche Bank (2001).

New Zealand, and the U.S. are expected to introduce new products. Although the Stirling engines currently under development range from several hundred watts to over 100 kilowatts, the most activity seems to focus on units in the range of one to three kilowatts. These units, targeted for the residential market, can be packaged to either be connected to the grid or operate independently. Unit electricity costs in the range of 12-15 cents/kWh are predicted by manufacturers and are considered feasible with thermal energy recovery for hot water use.

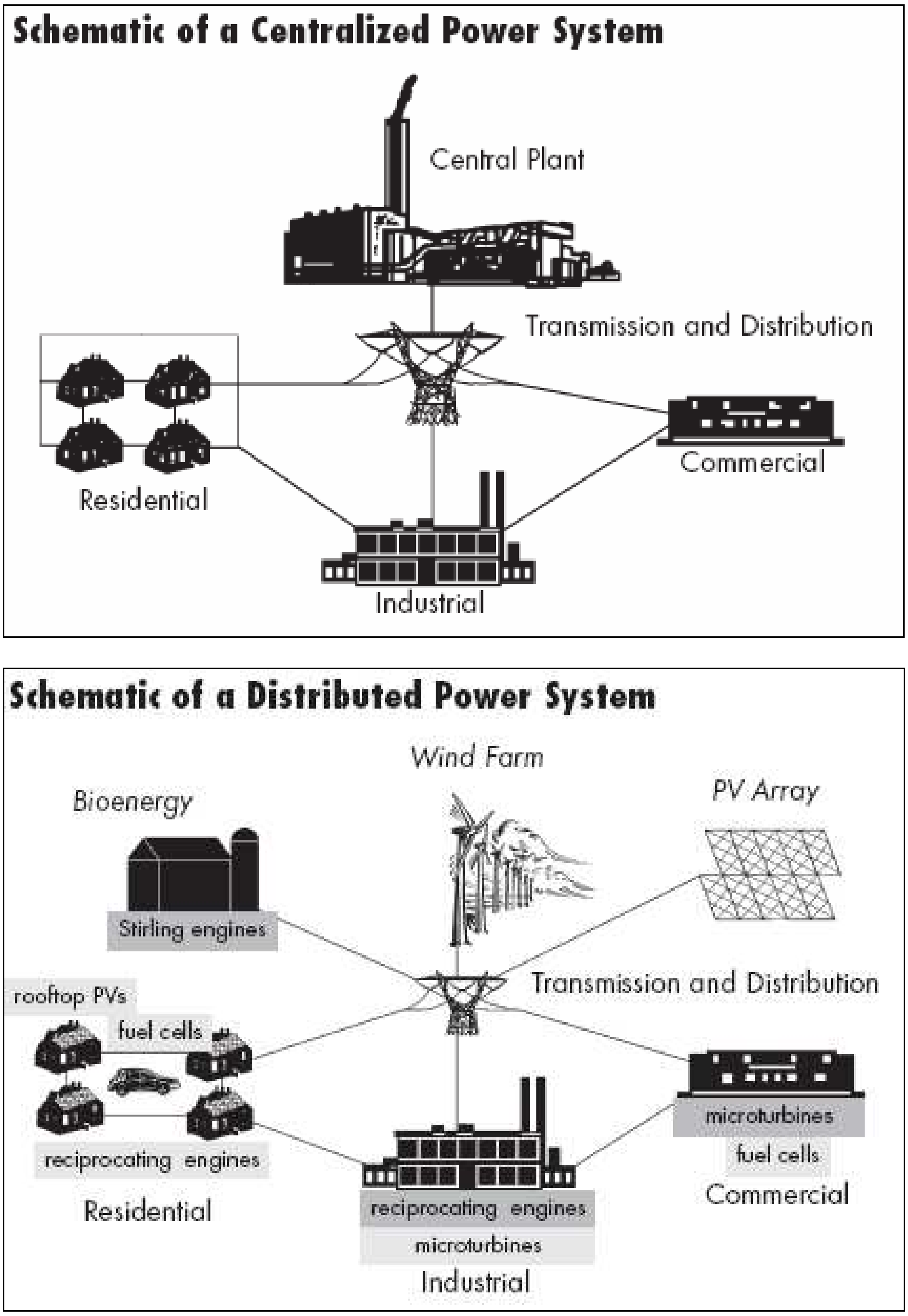
Distributed Generation and the Grid

Depending on the size and scale of specific projects and aggregation of the distributed generation (DG) sources, development of these supply resources will generally increase the amount of generation connected to distribution networks (less than 50 kV) close to the end-use customer or loads. The connection could be behind the customer's meter or to the distribution feeder.

Traditional end-user DG applications include standby or emergency power, combined heat and power (CHP), small-scale renewable energy (photovoltaic, wind and biomass), and economic peak shaving to manage utility capacity charges. Looking ahead, there is good reason to believe that the market for economic applications of DG will improve in response to potential increases in energy costs and in response to system reliability and security concerns.

Utility grid-sited DG applications have traditionally focused on peaking applications for the most extreme conditions, typically well below 500 hours per year, as well as larger-scale intermittent renewable generation. The peaking applications use proven diesel engine and natural gas or diesel-fuelled gas turbine technology, often in mobile trailer-mounted packages. Recently, the emergence of clean natural gas-fuelled reciprocating gas turbine and gas engine technology options in the 5-15 MW size class has allowed utility planners to use DG for grid support load management, with operation ranging from 500 to 3,500 hours per year based on economic dispatch. Figure 5.2 illustrates emerging DG technologies within an integrated network compared to a centralized power system.

Figure 5.2 – Emerging Distributed Supply Within the Integrated Network



Source: Dan W. Reicher, Assistant Secretary for Energy Efficiency and Renewable Energy, U.S. DOE, Testimony Before the Committee on Energy and Natural Resources, U.S. Senate Hearing on Distributed Power Generation, 22 June 1999..

Smaller types of distributed plant will, by their nature, be sited either at or close to customer sites. These include micro-, small- and district CHP, CHP combined with seasonal storage (for reducing the peak demand for air-conditioning in the summer or peak heating in the winter), fuel-cells and possibly photovoltaics. Biomass generation will need to be near agricultural or forestry fuel sources and generally some distance from major cities. All these developments will have an impact primarily on the distribution network, but over time, with increased penetration, will result in changes to the regional flows of power through the transmission network. The uptake and commitment to projects under the Standard Offer Program for both Renewable Energy and for Clean Energy will provide an early indication of the expected penetration of these technologies and also the technical feasibility and cost-effectiveness of the options.

Distributed generation benefits identified by utilities include:

- transmission and distribution (T&D) investment deferrals in T&D capacity to meet growing demands
- transmission system benefits by generating power at or very near the point of consumption where there is congestion whereby DG sources can effectively increase the T&D network capacity
- increased generating capacity
- reliability enhancements including local reactive power (VARs) that can aid utilities in maintaining system voltage
- reduced T&D electric losses associated with transporting power over the T&D system.

The marginal cost of upgrading an existing electric utility distribution system to serve new load can range from 5 cents/kWh to over 25 cents/kWh, depending on the utility’s cost structure and the nature of its service territory. Remote regions, as well as already congested urban service territories, are likely to have above-average marginal costs creating opportunities for economic distributed generation applications.

Benefits to end users from DG applications, beyond electricity cost savings, include:

- reduced energy costs for thermal energy loads through CHP to produce steam and water that can be used in industrial processes or for space heating and cooling requirements
- increased power reliability by reducing power outages associated with utility supply
- improved power quality by reducing or eliminating grid voltage variation and harmonics that negatively affect a customer’s sensitive loads
- new sources of revenue that allow customers to sell excess power or ancillary services to power markets and also decrease exposure to electricity price volatility.

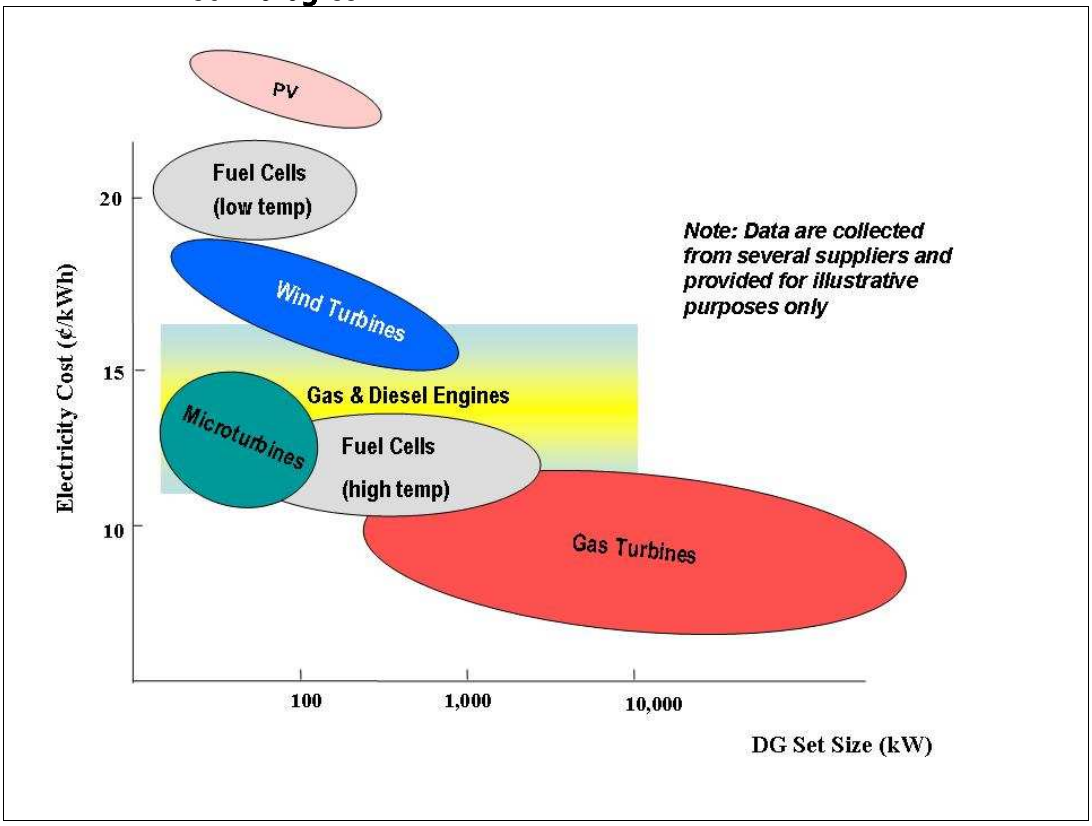
In the long term, depending on the commercial viability of new and emerging distributed generation technologies, there will be ongoing need for integration with the high voltage network. As the availability of distributed and renewable sources of generation increases, it may be necessary to modify the transmission system in certain locations to facilitate two-way flows of power on the network. The integrated network is a flexible and economic way of transporting reliable and high quality power to match generation with demand and adaptive technologies will need to be implemented to facilitate the development of renewable and emerging sources of new supply.

Figure 5.3 provides an illustration of unit energy cost of distributed generation technologies and Figure 5.4 shows the installed cost as ($/kW). The information presented here is based on suppliers' data. Costs and unit sizes are shown as envelopes to illustrate relative costs and unit sizes. Note that the vertical scale is broken to contain the full range of data.

While the costs shown here are total installed cost, a true comparison must take into account benefits which a particular technology offers for any given location. For example, exhaust heat may be useful in some high temperature applications and could be assigned a value which could positively affect the economic case for a specific application. In other areas, quiet operation may be a significant intangible benefit, although a monetary value could not be assigned.

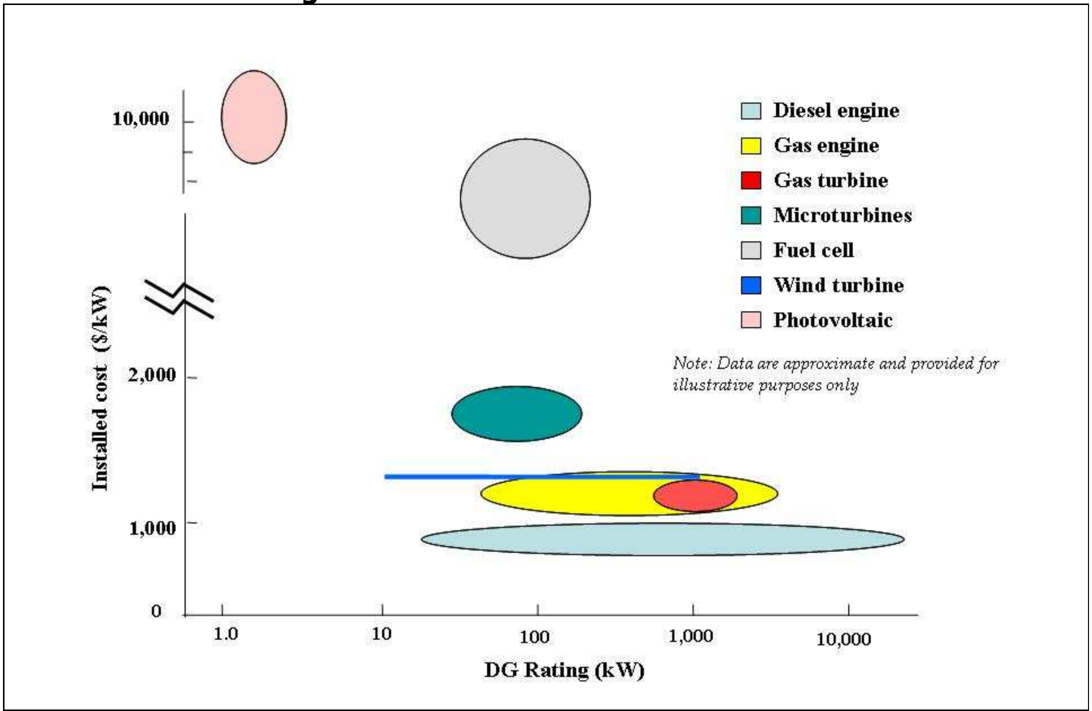
While there are significant differences in cost between the various technologies, the gap is expected to narrow considerably in the next 5 to 10 years. Indeed, it is expected that the costs for all distributed generation will fall with fuel cells and PV seeing the greatest reductions (in the order of 80 percent).

Figure 5.3 – Unit Energy Cost Comparisons of Distributed Generation Technologies



Source: OPA

Figure 5.4 – Installed Cost Comparisons of Distributed Generation Technologies



Source: OPA

Integration of Distributed Generation

The bulk electricity system remains, by its nature, an integrated entity. Successful introduction of new forms of generation into the existing transmission and distribution networks will require that the barriers to distributed generation be addressed.

Although, widespread availability of distributed generation in the Ontario market is expected to take time, the initial focus will most likely be at the level of connection to the distribution network. The technical and practical issues at the distribution level include:

- capacity restrictions, particularly as a result of the low load levels on the existing network in rural areas
- generation connection standards and procedures to address fault level restrictions and safety considerations.

Other key factors in facilitating the development of distributed generation include accessible processes for market entry, effective information flows, and transparent terms for connection and use of networks. The barriers to adoption comprise the technical restrictions, contractual requirements, and associated costs for connecting customer-owned generators to the grid. For many types of distributed generation, the requirements are often seen as excessive and time-consuming, resulting in additional unwarranted costs and significant project delays.

Options to Reduce Barriers to Distributed Generation

The development of the Standard Offer Program for generators has resulted in the OPA and the Ontario Energy Board taking steps to identify and reduce barriers to connection and supplying electricity in Ontario. The Standard Offer Program offers certainty with regard to thepricing and the terms and conditions of the purchase of electricity from smaller scale (<= 10 MW) generators.

Some of the steps that have been taken by the Ontario Energy Board to remove barriers to small scale generators include:

- standardizing the Connection Agreements between electricity distributors and generators for all generation projects less than 10 MW;
- simplifying the generator licensing process and reducing fees;
- establishing a consistent generator queuing process for allocating available distribution capacity; and
- removing the requirement for 4-quadrant metering for all generators regardless of size.

The Standard Offer Programs for Renewable Energy and Clean Energy are the first significant distributed generation procurement programs in Ontario and it is expected that hundreds of new generators will connect to the distribution grid as a result. Based on experience and the level of success of these programs, further barriers are expected to be identified both within the electricity sector as well as through other regulatory approval processes. This experience will assist the OPA and the Ontario Energy Board in determining the extent to which additional steps are appropriate for further facilitating distributed generation throughout Ontario.

Increased Role for Distributed Generation

The Standard Offer Program and recent work at the Ontario Energy Board on connection standards are important initiatives to help improve access for and increase the role of distributed generation in the supply mix.

The Standard Offer Program offers 42 cents/kWh for energy produced by solar photovoltaic technologies and 11 cents/kWh for a range of distributed generation technologies. With the development of a functioning competitive electricity market in Ontario, the OPA recognizes that the role of distributed generation in the Ontario energy mix for the period through to 2025 will increase. For the IPSP, an estimated total of 600 MW installed capacity of distributed generation over the plan period is a reasonable working assumption.

OPA is seeking stakeholder input and interest in further exploring the potential for distributed generation in Ontario.

5.2 Gasification

Recent Information and Analysis

The immediate deployment of integrated gasification with combined cycle (IGCC) power plants, while technically feasible, involves significant technological and financing risks related to commercial deployment of the concept. IGCC, combined with emergent carbon capture and storage capabilities (CCS), provides a promising technology option for effective removal of carbon dioxide, thereby reducing the impacts on climate change.

A number of IGCC plants of around 250 MW are operating in Europe and the United States. These include:[18]

- Buggenum, Netherlands, 253 MW coal, 2000
- Shell Pernis Netherlands, 120 MW cogeneration, refinery bottoms
- Elcogas, Puertollano, Spain, 298 MW, Prenflo gasifier, 50:50 coal petroleum coke, 1998
- Polk, Tampa, U.S.A., 250 MW coal and/or coke, 2001
- Wabash River, U.S.A., 262 MW, coal and/or coke, 2001
- Sarlux, Italy, 551 MW, petroleum coke
- Negishi, Japan, 342 MW, asphalt, 2003
- Pino Pine, U.S.A., 107 MW, fluidized bed gasifier, 1998.

In addition to these operating plants, design studies also exist for larger plants in the 600 MW and 1,000 MW range.[19] A variety of IGCC gasification processes is available.[20] Since IGCC units operate under pressure, fuel handling is more complicated than for conventional coal-fired generating stations. Gasifiers are limited by size considerations to about 250 MW and appear to require substantial maintenance. The use of multiple gasifiers, however, is possible.

Despite these considerations, gasification technology is considered fully proven and commercially available as a supply of gas (i.e., not electricity), with 385 gasifiers in operation at 117 projects around the world.[21] However, IGCC applications have mostly used petroleum residuals rather than coal.

OPA anticipates that by 2015 current initiatives in the U.S. will have demonstrated the efficacy of IGCC and IGCC may become a viable future option for Ontario. While the opportunities for sequestration of carbon dioxide in Ontario seem limited, it is possible that capture and sequestration techniques may also be available about this time. OPA will continue to monitor developments of the gasification technology.

The potential for IGCC adoption in Ontario can be assessed in two ways. If continuing high gas prices are forecast, then IGCC may well be an economic source of supply, utilizing the large

[18] See www.clean-energy.us/success.htm.
[19] *"A Large Coal IGCC Power Plant"* Amick, Geosits, Herbanek, Kramer and Tam, 2002 www.bechtel.com/PDF/BIP/22008.pdf.
[20] Global E Gas (ConocoPhillips), Texaco (C-T soon to be GE), Shell and Prenflo.
[21] *"National Gasification Strategy- Gasification of Coal & Biomass as a Domestic Gas Supply Option"* Rosenberg, Walker and Alpern, 2005. (www.innovations.harvard.edu/showdoc.html?id=4972).

reserves of coal with low environmental impacts. Alternatively, if IGCC is thought of as a hedge against high gas prices, its use in portfolios with high gas usage would then be appropriate.

According to CERI, IGCC capital costs (without CO_2 capture) are in the range of US $1,200 to US $1,400/kW, which is about 20 to 30 percent more than pulverized coal generating costs. The costs of CO_2 capture and sequestration from new IGCC plants add 40 to 50 percent to the cost of electricity, compared to 80 to 90 percent for new conventional coal plants.[22]

Being a coal-fired plant, an IGCC project raises the issues of the relative costs of transport of coal versus electricity. The infrastructure exists to bring Appalachian coal to southern Ontario. Since there may be problems firming up transmission capacity to bring power from a plant in the area of the mine mouth, siting such a plant using Appalachian coal in southern Ontario could be economic. For western Canadian coal, it may make sense to make use of east-west transmission that would accompany a waterpower purchase from Manitoba. Such a plant would be sited in Saskatchewan or Alberta, close to the source of the coal, although using low quality western Canadian coals would probably have an adverse effect on the economics of such a proposal.

IGCC is a reasonably new technology for Ontario. The cost estimates used in the IPSP are more uncertain than for established technologies. For the purpose of the IPSP, it is intended to include a 250 MW IGCC plant coming into service in 2020, as a reminder that this technology may have a role to play. However no action, other than monitoring worldwide developments, is expected to be proposed in the near term.

[22] See "A summary of recent….." Op. Cit, EPRI uses transportation and sequestration costs of $5/Metric tonne.

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Appendix A: Biomass Energy Conversion Technologies

Direct Combustion

The incinerator is a familiar and commercially proven method of extracting heat energy by burning a combustible fuel or fuels. Modern combustion methods are often accompanied by sophisticated controls to ensure more efficient burns, as well as emissions and waste management controls to meet or exceed environmental regulations and standards. In the past, direct combustion units have been frequently used with little or no recovery of thermal energy from the combustion, besides the production of steam to drive turbines and generator sets. Recovering excess heat of combustion is now commonly practiced to provide thermal energy to other users, which can significantly increase the overall efficiency of the plant.

Direct combustion is suitable for a wide variety of biomass types, but most require some degree of drying or de-watering prior to combustion. High moisture content biomass may need to be supplemented with natural gas to achieve effective combustion. In direct combustion plants, biomass can be the supplemental fuel as well, such as co-firing biomass in existing coal burners. A typical coal-fired power plant can co-fire up to 10 to 15 percent biomass before significant modifications to the plant would be required.

Conventional combustion of biomass has similar operational capabilities to the existing coal fired power plants in Ontario. Both systems generate steam to drive turbines that produce electricity and thus, the load-following capability of these systems is limited by the time it takes to stoke boiler fires and produce more steam. Consequently, conventional generation is better suited to intermediate generation and is not considered a highly flexible, dispatchable source of power. If combined heat and power configurations are used, the system would be better suited for baseload generation.

Thermo-chemical Processes

Gasification

Gasification refers to a group of technologies capable of converting organic materials into a combustible gas mixture by partial oxidation at elevated temperatures. The large, complex organic molecules making up biomass are rapidly broken down into smaller molecules in the presence of oxygen. The volume of biomass is reduced significantly while most of the energy content in the original fuel is retained in the product gas (“syngas”). Syngas is composed primarily of methane and carbon dioxide.

Gasification is suitable for a wide variety of biomass types, including cellulosic and ligno-cellulosic plants such as trees and waste wood. In their raw form, these materials are resistant to some other forms of degradation, including anaerobic digestion (described below).

Gasification can also be used to convert biosolids, organic fraction of municipal solid waste (MSW), and other solid biomass sources to syngas.

At small scales, biomass gasification has been commercially available for some time. At larger scales, the technology has been demonstrated utilizing fluidized bed and circulating fluidized bed systems integrated with combined cycle gas and steam turbines for electricity generation. Gasification offers some potential as a controllable resource to satisfy peak load demand. Gas storability entails capital costs, so it would have to be attractive to developers to invest in gas storage equipment and infrastructure. Thus, although biomass gasification plants are technically capable of providing peaking power, it is not known whether developers will develop the gas storage capability without adequate incentives.

Plasma Gasification

A form of gasification, plasma gasification uses the intense heat from a plasma arc torch to break down biomass into its most basic molecular constituents. Plasma gasification produces a high quality syngas, rich in methane, carbon monoxide and hydrogen, as well as an inert, vitrified[23] “slag”, using a wide variety of biomass and non-biomass feedstocks. The slag, composed of non-volatile components in the feedstock, cannot be converted into fuel and is typically cooled and processed for secondary uses such as supplementing road building or construction materials.

The syngas product can be burned to produce steam for electrical generation, or it can be cleaned of impurities to be combusted in a gas engine or turbine in a similar manner to conventional natural gas. This process is reported to produce fewer emissions than direct combustion of the feedstock, however, the pilot project described next should provide useful insight into the environmental performance of this technology.

A partnership between the city of Ottawa and a plasma gasification developer has initiated construction of an evaluation facility at the Trail Road Landfill site in Ottawa, Ontario. This facility will process 85 tons of MSW per day and is expected to generate approximately 3.2 MW of electricity (enough to power 3,000 homes).[24] The demonstration facility will operate for a one year trial period, during which extensive testing should determine the performance and environmental implications of this technology. Elsewhere, Westinghouse and Hitachi have installed plasma gasification systems in Japan, primarily for the treatment of wastes, such as recovered plastics from automobiles at the end of their life cycles.

The gas produced during the plasma gasification process, can be stored and used during peak load hours in a similar manner to the treatment of natural gas today. As a result, plasma gasification could be an attractive source of peaking power, but operating at maximum capacity instead of storing the gas may be preferable to developers. Incentives would be required to trigger a shift towards increased load-following capabilities, away from baseload generation.

[23] Vitrification is a method of immobilizing waste by encasing it in a glass-like solid material.
[24] Plasco Energy Group (2005). See Plasma Gasification - Plasco Energy Group.

Pyrolysis

Pyrolysis of solid biomass is technologically similar to gasification, except that the biomass feedstocks are converted in an oxygen-deficient environment rather than in the presence of oxygen. The gaseous products produced in the first stage of the process are rapidly quenched to form a mixture of liquids including combustible hydrocarbons and water (pyrolysis oil or "bio-liquids"). The oil products derived from the pyrolysis process can be used directly as fuel, but also as platform intermediates for producing chemicals, polymers and other value-added materials. The bio-liquid product can be further refined using a thermal cracking process to yield products of varying hydrocarbon chain lengths. Although suitable for a wide variety of biomass as well as non-biomass feedstocks (such as plastics and used tires), the quality of the bio-liquid product can vary depending on the feedstock used.

The bio-liquid created during pyrolysis holds significant potential to increase the storability and hence, the dispatch capability, of biomass energy. The product can be stored using conventional drums or tanks, transported by truck or rail, and can provide a source of fuel to be used for generating electricity during periods of peak demand and in areas away from the source of the biomass. Pyrolysis is thus one of the most promising sources of controllable generation from biomass. On the other hand, competition with users that desire bio-liquid as an intermediate for purposes other than electricity generation, such as chemicals, transportation fuels or pharmaceuticals, may limit supply and create difficulty in amassing large enough reserves at reasonable prices for reliable use as a dispatchable source of energy.

Biological Processes

Anaerobic Digestion

Anaerobic digestion is a biological process that produces a combustible gas primarily composed of methane (CH_4) and carbon dioxide (CO_2), known as syngas or "biogas". Biogas can be produced from organic residues such as livestock manure, sewage sludge, crop and grain handling residues, food processing waste, restaurant fats, oils and greases, as well as from crops and grasses grown specifically for their energy content. Unlike the other biomass conversion technologies, anaerobic digestion can utilize feedstocks composed mostly of water (such as manure).

Anaerobic digestion occurs naturally (in peat bogs, lake bottoms, or covered landfills) or in controlled environments such as sealed vessels. Naturally occurring microbes produce methane as a by-product as they decompose organic matter in the absence of oxygen (anaerobic). Anaerobic digestion is suitable for wet or dry biomass materials, but is not suitable for woody materials such as trees and wood waste because of high cellulose contents. Depending on the feedstock and the system design, biogas can contain from 55 to 75 percent pure methane. State-of-the-art systems report producing biogas that is more than 95 percent pure methane, but producing a biogas of such purity generally requires additional equipment to remove carbon dioxide, hydrogen sulphide, or other impurities from the gas.

Many anaerobic digestion technologies are commercially available and have demonstrated success using agricultural residues and municipal and industrial wastewater. Where uncontrolled decomposition of organic material can cause odours and water pollution such as in large dairies, anaerobic digestion in closed vessels reduces odours and liquid waste disposal problems, in addition to producing a biogas fuel and valuable odour-free fertilizer products.

The nature of biogas production by anaerobic digesters makes this technology an attractive candidate to act as a peaking resource. Many anaerobic digester systems are coupled with gas storage systems within the bladder of the unit, and depending on the substrates used and their corresponding biogas production rates, 10 hours of biogas or more can be stored within the unit.[25] The addition of extra storage tanks outside of the system would easily increase storage capacity, allowing generation to occur during times of peak demand and the highest sale prices.

Still, the likelihood of small generators choosing to invest in extra storage, or even to utilize the 10 hour storage capabilities of their units, is unclear in current Ontario market conditions. To date, the classic approach in Europe and elsewhere has been to limit the operating requirements for electricity generation by producing output at a consistent rate with gas generation. Further study would be necessary to determine the economic feasibility of increased storage capacity, as well as the effects of Standard Offer Programs on the likelihood of Ontario generators choosing to use their output as a dispatchable resource.

[25] Brian Gannon "*Key Elements of Biogas Energy Systems, Anaerobic Digesters*" 2006