ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2003

ONTARIO POWER GENERATION INC.

April 30, 2004

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It is anticipated that there will be important changes made to Ontario's electricity market and the role of OPG within it. Any changes could significantly alter the objectives, rules, regulations and operations of Ontario's electricity marketplace and could significantly impact OPG and its role in the Ontario electricity market. As a result, the information in this annual information form may not be reflective of the on-going operations, financial position or prospects of OPG. All references to dollars in this annual information form are to Canadian dollars, "Province" refers to the Government of the Province of Ontario (provincial government entity) and "Ontario" refers to the Province of Ontario (geographic area). This annual information form uses certain terms, which are defined in the "Glossary".

ITEM 1 - CORPORATE STRUCTURE

Ontario Power Generation Inc. (the "Corporation") was incorporated under the *Business Corporations Act* (Ontario) (the "OBCA") on December 1, 1998 and is wholly owned by the Province. On April 1, 1999, as part of the reorganization of Ontario Hydro and the related restructuring of the electricity industry in Ontario, the Corporation and its subsidiaries (collectively "OPG") purchased and assumed certain employees, assets, rights and obligations of the electricity generation business of Ontario Hydro. On January 1, 2003, 16 of its wholly-owned subsidiaries were amalgamated with the Corporation under the OBCA. The primary purpose of the amalgamation was to simplify the corporate structure.

OPG's principal business is the generation and sale of electricity. OPG sells the electricity that it generates into the markets administered by the Independent Electricity Market Operator (the "IMO"). As of December 31, 2003, OPG's electricity generating portfolio had a total in-service capacity of 22,777 megawatts ("MW"). This consisted of: (i) three nuclear stations with an in-service capacity of 6,103 MW (excluding the three laid up units at OPG's Pickering A nuclear generating station, which have an in-service capacity of 1,545 MW); (ii) six fossil-fuelled stations with an in-service capacity of 9,718 MW; (iii) 36 hydroelectric stations with an in-service capacity of 6,823 MW; and (iv) 32 EcoLogo^{M}-certified green power facilities with an in-service capacity of 133 MW, comprising 29 small hydroelectric and three wind power stations (one of which, Huron Wind, is co-owned by OPG and Bruce Power, L.P. ("Bruce Power")). The Bruce A and B nuclear generating stations are owned by OPG and leased on a long term basis to Bruce Power and are excluded from OPG's generation statistics since the closing of the transaction.

OPG's corporate structure is summarized as follows (each of the named corporations is wholly-owned by the Corporation and incorporated under the OBCA and each of the limited partnerships was formed under the *Limited Partnerships Act* (Ontario)):

> ***Core Business:*** OPG holds it's hydroelectric and fossil generation assets directly through the Corporation and holds its nuclear generation assets through subsidiaries of the Corporation. The nuclear generation assets are leased back to and operated by the Corporation. OPG-700 University Inc. holds and leases back to the Corporation the property where OPG's corporate head office is located. The Corporation also has subsidiaries that have been incorporated for specific purposes, however, these subsidiaries are either not currently operational or their total assets and sales and operating revenues are less than 10% of the consolidated assets and sales and operating revenues of OPG.
>
> ***Other Investments:*** OPG holds a 100% interest in OPG Ventures Inc. (a venture capital investment company), a 50% interest in Brighton Beach Power Ltd., a 49.95% interest in Brighton Beach Power L.P., a 50% interest in Huron Wind Inc., a 49.99% interest in Huron Wind L.P., a 50% interest in Portlands Energy Centre Inc. and a 49.95% interest in Portlands Energy Centre L.P.

In May 2001, OPG completed the long term lease of its Bruce A and Bruce B generating stations to Bruce Power, L.P. and in May 2002 OPG sold four hydroelectric stations on the Mississagi River System to Mississagi Power Trust. The information contained in this annual information form applicable to periods after commencement of the Bruce lease and completion of the Mississagi sale does not include these stations, unless specifically noted to the contrary.

ITEM 2 - BACKGROUND

Overview

The electricity industry is principally made up of four components: generation, transmission, distribution and marketing of electricity and other related services in wholesale and retail markets. Generation is the production of electricity at generating stations. Transmission is the transfer of electricity across high-voltage power lines from generating stations to local areas or large users. Distribution is the delivery of electricity within local areas to homes and businesses using relatively low-voltage power lines. Marketing of energy and other related services includes the provision of financial or risk management products that provide price volatility protection.

Electricity has traditionally been generated in Ontario by large, centralized generating stations. These stations are generally classified by (i) the type of fuel used at the station, (ii) capacity, typically expressed in megawatts ("MW"); and (iii) dispatch mode (i.e. whether the electricity generated by a particular generating station is dispatched to meet peak, intermediate or base load demand). The energy produced by a station is generally expressed in terms of megawatt-hours ("MWh").

Generating stations are called upon to produce electricity and are "dispatched" based on demand. "Base load capacity" stations operate virtually continuously to satisfy relatively constant demand. "Peaking capacity" stations operate intermittently to provide electricity during periods of maximum demand. "Intermediate capacity" stations operate fewer hours than base load capacity stations but more than peaking capacity stations. Typically, base load facilities are higher capital cost, lower operating cost facilities, while intermediate and peaking facilities are characterized by lower capital costs but higher operating costs and greater flexibility. These facilities have generally been dispatched based on a system whereby the lowest available marginal cost generating unit is dispatched to meet the "next" unit of electricity demanded in the area served by the electrical system.

Electricity is an essential commodity that cannot be easily or economically be stored in large volumes. Generation of electricity must therefore instantaneously match demand if the stability and reliability of the system is to be maintained. Consequently, it is important to coordinate the supply of and demand for electricity. This responsibility is typically assigned to independent system operators. Electricity systems have evolved on a regional basis and are generally interconnected with their neighbouring regional power grids. Such interconnections not only enhance system reliability, but also permit the economic purchase and sale of electricity in interconnected electricity markets.

Traditionally, electric utilities have been vertically integrated monopolies that built generating, transmission and distribution facilities to serve the needs of the consumers in their service territories. Significant capital commitments were required to construct large power stations and to coordinate generation, transmission and distribution. Historically, the price of electricity was set by a regulatory process, rather than by market forces, whereby rates were established to recover the cost of producing and delivering power to consumers, as well as recovery of capital costs. Under this monopoly service regime, consumers had no choice of supplier and suppliers were not free to pursue consumers outside their designated service territories.

Restructuring Ontario Hydro

Until April 1999, Ontario Hydro was a vertically integrated electricity utility owned by the Province and the sole supplier of electricity for most of Ontario's consumers. In November 1997, the Province released a policy paper entitled "Direction for Change" which set out a restructuring plan for the electricity industry in Ontario. In January 1998, the Minister of Energy, Science and Technology established the Market Design Committee to make recommendations to the Province on the commercialization of and design of an independent market operator to manage the wholesale electricity market. The independent market operator was to oversee the operation of the integrated power system and to create the rules and protocols necessary to implement a competitive electricity market in Ontario. The Market Design Committee produced three reports in 1998 and a final report in January 1999. During this period, the market restructuring legislation, the *Energy Competition Act, 1998* (Ontario), was enacted.

As a result of this process, five principal successors to Ontario Hydro's integrated electricity businesses began operating as separate entities on April 1, 1999:

- Ontario Power Generation Inc., which purchased and assumed the electricity generation, wholesale energy and ancillary services businesses from Ontario Hydro;
- Hydro One Inc. ("Hydro One"), which purchased and assumed the transmission, rural distribution and retail energy services businesses from Ontario Hydro;
- the Independent Electricity Market Operator (the "IMO"), which was formed to act as both the independent electricity system operator and market operator, responsible for the dispatch of generation to meet demand, the control of the Ontario transmission grid and the operation of energy and ancillary markets;
- the Electrical Safety Authority, which was established to carry out electrical equipment and electrical wiring installation inspection functions; and
- Ontario Electricity Financial Corporation (the "OEFC"), which remains responsible for managing and retiring Ontario Hydro's outstanding debt and other obligations and for the administration of non-utility generator contracts in a manner compatible with the market design.

Evolution of Ontario's Electricity Market

As a result of the opening of Ontario's electricity market to competition on May 1, 2002 ("Market Opening"), there were significant changes in the way the electricity industry operates in Ontario. Generators, both from within and outside Ontario, currently compete to sell electricity through the IMO-administered spot market. Other market participants include local distribution companies, large industrial facilities directly connected to the transmission system, other large industrial and commercial customers connected to the distribution system who opt to be wholesale market participants and retailers.

The IMO functions both as independent system operator, ensuring overall system adequacy, reliability and stability by controlling physical dispatch and directing the operation of the transmission system, and as an independent market operator of the spot market which in effect operates as a power exchange. As the market operator, it functions as the clearing house for the settlement of spot transactions by suppliers and purchasers of electricity in the IMO spot market. See "*Business of OPG – Regulation – Ontario's Electricity Industry – The IMO*".

All market participants must be authorized by the IMO to cause or permit electricity to be conveyed into, through or out of the IMO-controlled grid and to participate in the IMO-administered markets. All market participants that supply electricity into, or take electricity from, the IMO-controlled grid must install approved interval metering at their connection points to the grid. The IMO dispatches generators based on their offers to sell electricity and operating reserve. See "*Business of OPG - Regulation - Ontario's Electricity Industry - The IMO*".

Generators, such as OPG, function as suppliers of energy and operating reserve that is priced by the IMO-administered market. Prices in the IMO-administered market will fluctuate. Generators may fix the price that they receive for the sale of electricity by entering into bilateral or derivative contracts with third parties.

In addition, the IMO and all generators, transmitters, distributors, wholesale sellers, wholesale buyers and retailers must obtain a licence from the Ontario Energy Board ("OEB") in order to participate in the Ontario electricity market. OPG has received licences from the OEB as a generator, a wholesale buyer and seller and a retailer.

Consumers pay for the electricity purchased as well as for transmission, distribution and charges payable to the IMO in relation to its activities and other costs incurred (referred to as "administration charges" and "uplift charges", respectively). In addition, a debt retirement charge of $7.00 per MWh is levied to service part of OEFC's debt.

The original design of the Ontario electricity market contemplated that all consumers would pay a floating price for at least a portion of the electricity they purchased, unless they chose to enter into a fixed price contract, however, most retail customers now pay a fixed price for the electricity they consume.

On December 9, 2002, the Province modified the legislation governing the Ontario electricity market by enacting the *Electricity Pricing, Conservation and Supply Act, 2002*. One of the key features of this legislation, retroactive to Market Opening, was to fix the price paid by 'low-volume consumers' (consumers using less than 150,000 kWh annually, although this cap was subsequently increased to 250,000 kWh, as described below) and other 'designated consumers' at 4.3 cents/kWh. 'Designated consumers' include municipalities, universities, colleges, school boards, hospitals, nursing homes, charities, condominiums, apartments and consumers who have a demand of 50 kW or less.

This legislation also: (i) fixed wholesale market uplift charges to distributors, low-volume consumers and designated consumers at 0.62 cents/kWh; (ii) capped charges for transmission and distribution and fees for the operation of the IMO at current levels; (iii) gave the Minister of Energy various additional powers, including the power to review Market Rule amendments to ensure that they do not unduly and adversely affect the interests of consumers with respect to price or the reliability or quality of electricity service and the power to oversee certain rates approved by the OEB; and (iv) created tax incentives to promote conservation, use of alternate fuels and support for clean energy production through a variety of mechanisms.

On March 21, 2003, the Province expanded the availability of the fixed price to include additional consumers when it announced a business protection plan for large electricity consumers in Ontario. Under this plan, consumers using up to 250,000 kWh per year became eligible to pay the fixed price of 4.3 cents/kWh, retroactive to May 1, 2002. Except for certain designated consumers, all consumers using above 250,000 kWh per year remained in the competitive wholesale and retail markets and received rebates under the terms of the Market Power Mitigation Agreement ("MPMA") arrangements (which are described below) for the 12 months ending April 30, 2003. Effective May 1, 2003, rebates to these customers were fixed at 50% of the amount by which the average spot price in the IMO-administered market exceeds 3.8 cents/kWh, with rebates paid on a quarterly basis. See "*Business of OPG - Regulation - Ontario's Electricity Industry - Market Power Mitigation - Rebate Mechanism and Transitional Price*".

This legislation and related regulations did not materially change the wholesale market for electricity, including the determination of energy prices in, or operation of, the IMO-administered market. However, the number of consumers exposed to wholesale market prices decreased. As a result of these changes, approximately 50% of the electricity consumed in Ontario became subject to this fixed price.

In June 2003, the Province established the Electricity Conservation and Supply Task Force (the "Supply Task Force") to provide an action plan outlining ways to attract new electricity generation and to identify and review options for the delivery of demand side management and demand response activities within the electricity sector.

The Province also made various announcements during the latter half of 2002 and the first half of 2003 relating to OPG, including: (i) the creation of the Pickering A Review Panel – an independent Panel to investigate the delays in and the cost of restarting Unit 4 of OPG's Pickering A nuclear generating station; (ii) acceleration of OPG's assessment of a new 550 MW generation project on OPG's Portlands' site in Toronto; (iii) possible construction of an additional tunnel at OPG's Beck hydroelectric generating station at Niagara; and (iv) a Ministry of Energy feasibility study of constructing another hydroelectric generating station at OPG's Beck generation station.

In October 2003, a new Government was elected in Ontario.

In November 2003, the Province introduced new legislation with respect to electricity pricing, intended to increase the fixed price paid by qualifying consumers in Ontario to more truly reflect the cost of electricity. On December 18, 2003, the *Ontario Energy Board Amendment Act (Electricity Pricing), 2003*, received Royal Assent. This legislation amends the *Ontario Energy Board Act, 1998*, by setting out the mechanism by which the commodity price for electricity is set for low-volume and designated consumers effective April 1, 2004. It also requires that sometime prior to May 1, 2005, the commodity price for these consumers will be determined by the OEB in accordance with regulations to be made at a later date. Regulations covering the period from April 1, 2004 to May 1, 2005 set the commodity price for these consumers at 4.7 cents/kWh for the first 750 kWh consumed during a calendar month. Consumption beyond 750 kWh each month is priced at 5.5 cents/kWh. This legislation also provides that approval from the Minister of Energy is no longer required for amendments to rates for transmitting electricity.

In December 2003, the Province received the Report of the Pickering A Review Panel, which found that there were a number of problems associated with the restart of Unit 4. (See "*Business of OPG – Recent Developments – Pickering A Return to Service*"). In addition, the Province announced it had accepted the resignations of OPG's Chairman, President and Chief Executive Officer and Chief Operating Officer, as well as the resignations of all other members of the Board of Directors. The Province also passed an "Amended and Restated Declaration of the Shareholder" under the OBCA restricting the powers of the Board of Directors with respect to certain personnel matters and expenditures related to Pickering A, Units 1, 2 and 3. The Province then announced the appointment of a new Chair and Board of Directors for an interim period.

Also in December 2003, the Province asked OPG's new Board of Directors to undertake a financial review of the operations of OPG. In January 2004, the Board appointed KPMG LLP to conduct a review of OPG's actual financial performance compared to the results projected in OPG's 1999 business plan for the 1999 to 2003 period (the "1999 Baseline Plan") and to identify and quantify the impact of the changes that occurred relative to the 1999 Baseline Plan, as well as those changes that occurred each year compared to the plan for that year.

In addition, in December 2003, the Province also announced the formation of a separate OPG Review Committee to provide advice on long-term issues relating to OPG. The OPG Review Committee was asked to make recommendations on the role of OPG in the Ontario electricity market, the appropriate future structure of OPG, its corporate governance and senior management structure and the potential return to service of Pickering A Units 1, 2 and 3.

In January 2004, the Province released the report of the Supply Task Force. Recommendations of the Supply Task Force pertaining to market design addressed regulated pricing of electricity, authority of the IMO and supply arrangements. In addition, the Supply Task Force provided a variety of recommendations designed to encourage conservation; promote renewable power technologies and distributed generation; and improve the responsiveness and reliability of the power grid. The Supply Task Force also made recommendations specifically related to the future role of OPG, recognizing that the OPG Review Committee would be providing more advice on longer term issues related to OPG.

In February 2004, the Province announced it had selected NERA Economic Consulting to oversee a competitive process to contract for up to 2,500 MW of new generation capacity and/or demand-side management initiatives. The capacity initiatives are to be in place no later than 2007. The Province is also seeking 300 MW of renewable energy capacity to be in-service as soon as possible.

In March 2004, OPG's Board of Directors released the Financial Review of Operations for the period 1999 to December 31, 2003, undertaken at the request of the Province in December 2003. The report, completed by KPMG LLP, was primarily focused on comparing the actual financial results for the period with the 1999 Baseline Plan. The Review states that actual earnings before taxes for this period were $2.063 billion, resulting in an unfavourable variance from the 1999 Baseline Plan of $1.034 billion. A number of factors influenced this unfavourable variance. Of these, KPMG LLP concluded that the financial results were primarily impacted by the under-performance of OPG's nuclear stations. The nuclear budget in the 1999 Baseline Plan had been established based on assumptions in a 1997 Nuclear Asset Optimization Plan.

Also in March 2004, the report of the OPG Review Committee was released on the future of OPG, entitled "Transforming Ontario's Power Generation Company". The report contained detailed recommendations, including:

- The Province remain the sole shareholder of OPG.

- OPG retain ownership of its nuclear, major hydroelectric and fossil-fuel generating assets.

- OPG remain a single, commercially oriented company under the OBCA; that the current arrangement in which the Province does not guarantee OPG's debt continue; and that OPG be divided internally into two principal operating divisions, the nuclear division and the hydroelectric/fossil division.

- The Ontario Energy Board, acting as an independent body, approve the rate or rates at which the output of each OPG generating division is sold.

- For each generating division, the Ontario Energy Board base the rate or rates on cost of production plus a reasonable rate of return on capital that is comparable to the return earned by a regulated commercial company (or division of a company) with a similar business profile.

- OPG explore joint ventures, partnerships and leases for the operation and maintenance of its core generating assets where it is in its commercial interests to do so.

- OPG as a regulated company have a capital structure similar to other regulated commercial utilities.

- OPG proceed with the project to return Pickering A Unit 1 to service.

- The Board of OPG maintain the highest level of oversight for the duration of the project, including monitoring by third-party experts with direct accountability to the Board.

- The Board of OPG wait until there is clear evidence of success on the Unit 1 project before proceeding with any further development work on Unit 2 or 3.

- The same level of due diligence applied on the decision to proceed with Unit 1, including a business case analysis, be repeated for each of Units 2 and 3.

The OPG Review Committee also suggested that OPG focus on Ontario's needs, not OPG growth in the North American market.

Upon receipt of the report of the OPG Review Committee, the Province confirmed that the Minister of Energy will review the report in detail.

As a result of the report of the OPG Review Committee and the Province's response to it, there will be important changes made to Ontario's electricity market and the role of OPG within it.

On April 15, 2004, the Province released its proposals for Ontario's electricity sector. The Province indicated that it intends to introduce legislation on these proposed reforms in June. The reforms are to include:

- A new Ontario Power Authority tasked with ensuring an adequate, long-term supply of electricity including a new Conservation Secretariat, headed by a Chief Conservation Officer;

- A requirement that the Ministry of Energy set targets for conservation, the use of renewable energy, and the overall supply mix of electricity in Ontario;

- Greater encouragement of private sector investment in new generation (including contracting for new supply by the Ontario Power Authority) to help meet growing demand;

- A combination of a regulated and an unregulated, competitive electricity generation sector, which would see prices for electricity in Ontario set in two ways: part of the supply would be price-regulated by the Ontario Energy Board ("OEB"), which for OPG is expected to be its nuclear and base-load hydroelectric assets, and prices for all other supply would be set by the competitive market;

- A new standard rate plan offered to homeowners and small businesses, with prices that would be adjusted and approved periodically by the OEB, intended to ensure price stability while passing on the true cost of the electricity; and

- Choice for industrial and commercial consumers, who would continue to have flexibility offered by the market or could use other tools, such as fixed-price contracts, to help them manage their energy costs.

In addition, the Minister of Energy announced that the Honourable Jake Epp has been confirmed as OPG's Chairman of the Board effective immediately, and that a search would immediately commence for nine new members of OPG's Board of Directors, as well as a new Chief Executive Officer.

ITEM 3 - BUSINESS OF OPG

Overview

OPG is one of the larger electricity generators in North America. OPG's principal business is the generation and sale of electricity, which OPG sells into the IMO-administered market. Wholesale buyers purchase electricity from this market for use or sale within Ontario or to interconnected markets in other provinces and the U.S. northeast and midwest. OPG also buys and sells electricity from and into the interconnected markets of other provinces and the U.S. northeast and midwest. OPG's total generation from its own assets in 2003 was approximately 109.1 TWh. The Ontario market imported 10.4 TWh and exported 6.2 TWh in 2003. Of this, OPG imported 2.8 TWh and exported 2.0. TWh.

Most generators in Ontario, including OPG, must offer their production into the IMO-administered real-time energy market, or spot market, in order to be dispatched by the IMO. OPG is required to offer all available capacity as operating reserve.

Generators may also sell other ancillary products to the IMO-controlled grid, including reactive support/voltage control service, certified black start facilities and automatic generation control. OPG has negotiated ancillary services contracts with the IMO.

In addition, OPG provides financial risk management products to market participants and other customers in Ontario and in interconnected markets.

As of December 31, 2003, OPG's electricity generating portfolio had a total in-service capacity of 22,777 megawatts (MW). This consisted of: (i) three nuclear stations with an in-service capacity of 6,103 MW (excluding the three laid up units at OPG's Pickering A nuclear generating station, which have a capacity of 1,545 MW); (ii) six fossil-fuelled stations with an in-service capacity of 9,718 MW; (iii) 36 hydroelectric stations with an in-service capacity of 6,823 MW; and (iv) 32 EcoLogo[M]-certified green power facilities with an in-service capacity of 133 MW, comprising 29 small hydroelectric and three wind power stations (one of which, Huron Wind, is co-owned by OPG and Bruce Power).

The aggregate amount of electricity actually generated by OPG's stations is determined by the frequency with which OPG's stations are dispatched by the IMO to generate electricity and is therefore less than the capacity of the stations. The following chart summarizes the electricity generated by OPG over the past five years:

Five Year Generation Summary[(1)]

	1999		2000		2001		2002		2003	
	Total (TWh)	% of Total	Total (TWh)	% of Total	Total (TWh)	% of Total	Total (TWh)	% of Total	Total (TWh)	% of Total
Hydroelectric	33.6	26	34.0	25	33.7	27.7	34.3	29.6	32.4	29.7
Fossil	36.1	27	42.4	31	40.2	33.1	39.6	34.2	39.0	35.7
Nuclear	61.4	47	59.8	44	47.7	39.2	41.9	36.2	37.7	34.6
Total	131.1	100	136.2	100	121.6	100	115.8	100	109.1	100

Note:
(1) For a more detailed summary see the tables included under "*Business of OPG – Generation Operations*".

OPG currently operates approximately 74% of the available generation capacity in Ontario. In order to address the issue of the potential exercise of market power by OPG, OPG is subject to the "market power mitigation" measures established in its generating licence. These measures, the key elements of which are a rebate mechanism and a commitment to relinquish effective control over a major portion of its generating capacity, have had a significant influence on OPG's corporate strategy and business prospects. In 2003, the Province stated that there will be no further sale of publicly owned generation assets. OPG expects this issue, and the rebate mechanism, will be addressed by the Province, as part of its plan for the Ontario electricity market which the Province has indicated will be released during 2004. For more detailed information about these measures, see "*Business of OPG – Regulation – Ontario's Electricity Industry – Market Power Mitigation*".

Until further direction is obtained from the Province, OPG is continuing to pursue initiatives to ensure sufficient liquidity, increase productivity and the cost competitiveness of its generating assets, address the return to service of the Pickering A nuclear generating station, optimize its organizational structure, undertake sustainable development initiatives aimed at continuous and measurable improvement in environmental performance and continue with initiatives related to corporate governance.

OPG's portfolio of generation assets is diversified in terms of technology, fuel type and dispatch flexibility. Production costs are generally competitive with other generators in Ontario and the U.S. northeast and midwest, although higher than generators in Manitoba and Quebec which have a large supply of lower cost hydroelectric generation.

The performance of OPG's nuclear generating stations continued to improve from 1999 through 2002. By 2002, energy production had increased by 7 per cent over 1999 levels, while the net capacity factor had increased to 86% from 80% in 1999. These performance metrics declined in 2003 due to higher planned and forced outage days at the Pickering B nuclear generating station and higher planned outage days at OPG's Darlington nuclear generating station related to the regulatory requirement for major testing of the containment systems. In 2004, OPG plans to focus on initiatives that will improve the material condition of the physical plant and equipment, and improve energy production and capacity factors. It is expected that these initiatives will require significant increases in spending levels over at least the next five years. OPG is also focussing on improvements in control over projects and other productivity improvements.

OPG's fossil-fuelled generating stations operate as base load, intermediate and peaking facilities depending on the characteristics of the particular stations. Significant environmental improvements to these stations were completed during 2003, including the installation of selective catalytic reduction equipment for the purpose of emissions reduction on four units, two at Lambton and two at Nanticoke. Energy produced from OPG's fossil stations totalled 39.0 TWh in 2003, slightly below a production high of 42.4 TWh in 2000.

OPG has recently received confirmation from the Province that it will require the phase-out of the coal-fired generating stations, which is targeted for the end of 2007.

OPG's 65 hydroelectric generating stations are utilized primarily for baseload purposes due to their operating characteristics and low marginal production costs. Certain stations with water storage capabilities are also used as intermediate or peaking capacity. OPG's hydroelectric generation has ranged between 31.6 TWh and 38.8 TWh over the past 30 years. Due to significantly lower than normal water levels, hydroelectric generation in 2003 was 32.4 TWh, which is at the lower end of the 30 year average. In 2004, OPG plans to continue to invest in maintaining the long-term viability of its hydroelectric assets.

Recent Developments

August 14, 2003 Power Blackout

On August 14, 2003 a power blackout originating in the United States affected most of Ontario and the northeast United States. Following the blackout, OPG took immediate action to return its generating stations to service. Hydroelectric stations were reconnected to the transmission system within hours of the blackout. By Friday, August 15, 2003, about 60% of OPG's generating capacity, including OPG's hydroelectric stations and a significant portion of fossil station capacity and some nuclear capacity, was reconnected to the transmission system. By Monday, August 18, 2003, about 85% of OPG's available capacity was reconnected to the transmission system, including all four units at OPG's Darlington nuclear generating station. Generating capacity was fully restored by August 29, 2003.

OPG has estimated that the blackout resulted in a reduction in gross margin of approximately $60 million to $70 million and net income of approximately $40 million to $50 million, including the impact of lost revenue and higher operating costs to restore generating capacity.

On April 5, 2004, the U.S.-Canada Power System Outage Task Force issued its final report on the blackout. The main causes of the blackout were attributed to inadequate system understanding, situational awareness, tree trimming and reliability coordinator diagnostic support for northern Ohio. Recommendations included the following: implementation of mandatory and enforceable electricity reliability standards; addressing deficiencies identified; improving operator training and certification; and increasing the physical and cyber security of the network.

Going forward, some modifications are likely to be required to improve the ability of OPG's generating stations to respond to transmission system instability and withstand extended transmission system interruptions. The most significant impact is expected to be at OPG's Pickering B nuclear generating station.

Pickering A Return to Service

In August, 1999, the Board of Directors of OPG approved a plan to restart the four units at the Pickering A nuclear generating station which had been laid up in 1997, commencing with Unit 4.

In May 2003, in response to concerns related to delays in and high costs associated with the return to service of the Pickering A units, Ontario's then Minister of Energy announced that a three-member panel chaired by the Honourable Jake Epp had been appointed to review the Pickering A return to service project (the "Pickering A Review Panel"). The Pickering A Review Panel was asked to: (i) determine the reasons and reasonableness of the changes in the schedule and return to service dates, cost estimates and cost increases; (ii) review the financial reporting for project costs; (iii) make recommendations to the Minister on means of improving the management of the project to restore the Pickering A generating station to full operation, including measures to ensure the cost-effective and timely completion of the project; and (iv) make such further review, determination or recommendation as the Minister may require.

In September 2003, OPG declared Unit 4 to be commercially available and informed the IMO that the unit was available for dispatch into the Ontario market, adding 515 MW of base load capacity to OPG's electricity generation portfolio.

On December 4, 2003, the Report of the Pickering A Review Panel was released. The Panel found that initial assumptions regarding the scope and complexity of the project, regulatory requirements and work schedule were flawed. The Pickering A Review Panel also found that fundamental failures were evident in areas related to project management, including the failure to sufficiently plan the restart project, as well as the failure to put in place the necessary processes to monitor progress effectively. The Report concluded "the failings of the Unit 4 restart execution have been recognized by OPG, and over the past few months, more appropriate project management and oversight arrangements have been put in place". The Pickering A Review Panel recommended that a decision be made as soon as possible as to whether to continue with the restart of some or all of the remaining three units.

On March 15, 2004, the OPG Review Committee finalized its report. One of the recommendations contained in the report was that OPG proceed with the project to return Pickering A Unit 1 to service, subject to a variety of these conditions being met, including the condition that the Board of OPG maintain the highest level of oversight for the duration of the project, including monitoring by third-party experts with direct accountability to the Board. The report also recommended that the Board of OPG wait until there is clear evidence of success on the Unit 1 project before proceeding with any further development work on Unit 2 or 3 and that the same level of due diligence applied on the decision to proceed with Unit 1, including a business case analysis, be applied to any decision on Units 2 and 3.

OPG, through its Board of Directors, will make a recommendation to the Province, as shareholder, on whether to proceed with the restart of Unit 1 at the Pickering A nuclear generating station.

Closure of Coal Plants

A Provincial regulation requires that OPG's Lakeview coal-fired generating station cease burning coal by April 2005 and OPG has advised the IMO accordingly. In February 2004, the IMO directed OPG to assess the option of converting certain Lakeview units into synchronous condensers to provide reactive support and voltage control to the transmission system. In April 2004 the IMO revoked this direction.

The Province has announced that it is committed to closing the remainder of OPG's coal-fired generating stations by 2007. In April 2004, the Province confirmed that: "We remain committed to replacing coal-fired electricity generation in the Province. In so doing, we will never put Ontario consumers in jeopardy, and will be totally satisfied that adequate alternatives are in place before we replace coal". Based on this Provincial commitment, the Nanticoke, Lambton, Thunder Bay and Atikokan coal-fired generating stations would be removed from service before the end of their previously estimated useful lives. The retirement dates for the coal-fired generating stations were previously estimated as follows: Lambton – 2010 to 2020; Nanticoke – 2015; Thunder Bay – 2021; and Atikokan – 2025. The termination of operating cash flows from these stations after 2007 resulted in a pre-tax impairment loss of $576 million being recognized by OPG in 2003.

Fuel Channels

OPG has comprehensive inspection and testing programs in place in order to ascertain the physical condition of its nuclear generating stations. As a result of recent inspections of fuel channels, conditions were identified that will require acceleration of planned remediation programs at the Pickering B station. These findings will result in additional inspections of the fuel channels and will advance certain maintenance procedures in 2004 to 2006.

OPG's Markets

Ontario Market

In 2003, Ontario's population was approximately 12.2 million and Ontario's real gross domestic product ("GDP") was approximately $459 billion, reflecting an average GDP growth of 4.0% per year for the five-year period from the beginning of 1999 to the end of 2003. In 2003, Ontario's demand for electricity reached 151.7 TWh.

From 1994 to 2003, commercial energy consumption in Ontario (41% of total energy consumption in 2003) increased, reflecting growth in the economy since the early 1990s as evidenced by new construction, declining vacancy rates for existing office and multi-residential buildings and increased use of electronic equipment and air conditioning. Industrial energy consumption (33% of total energy consumption in 2003) decreased from 1990 to 1993 during a period of increasing electricity rates and decreasing economic activity, but increased steadily between 1997 and 2000. In 2001 and 2003 industrial demand decreased, due to a weak economy and declining energy consumption in Ontario's manufacturing and resource base segments. Demand in Ontario's residential sector (26% of energy consumption in 2003) declined from 1990 to 1997 due to conversion from electric space and water heating to natural gas and the replacement of some household appliances with more efficient units. Since reaching a low in 1997, however, residential energy consumption has increased in the last six years due to factors such as strong growth in housing construction and additional air conditioning installations.

The IMO is responsible for forecasting the demand for electricity in Ontario and for assessing whether the existing and proposed generation and transmission facilities are adequate to meet Ontario's needs. During times of negative reserve margins, the IMO anticipates and relies on the Ontario generators maximizing their availability to offer into the Ontario market, imports into the Ontario market and customers reducing their consumption, to ensure that there is sufficient electricity available to meet demand.

On a seasonal basis, demand for electricity in Ontario peaks in both the winter and the summer. Over the past 10 years, the demand for electricity in Ontario peaked in the winter, however, the increase in summer peak demand has outpaced the increase in winter peak demand, resulting in the demand for electricity in Ontario peaking in both the winter and the summer. In August 2002 the Province set a new summer peak of 25,414 MW and in January 2004 a new winter peak of 24,937 MW.

Interconnected Markets

The interconnected markets are those electricity markets in neighbouring provinces and states whose transmission systems are connected to the Ontario power grid either directly or through other contiguous interconnected markets. Ontario's markets are interconnected with the northeastern quadrant of North America, including the U.S. northeast and midwest, Manitoba and Québec. Market intermediaries wishing to sell electricity into the interconnected markets are required to purchase the electricity out of the IMO-administered spot market for resale into the interconnected markets.

As a result of the interconnection of the Ontario power grid with transmission systems in neighbouring provinces and states and the interconnections that, in turn, exist between those provinces and states and other jurisdictions, OPG is able to buy and sell energy into most electricity markets in the northeast and midwest of North America.

Interconnection transmission capabilities between Ontario and these interconnected markets are subject to physical limitations that are additionally impacted by seasonal variations. Weather and physical aspects of the transfer of power such as loop flows, resulting from the physical movement of power on the interconnected transmission grid, can also limit transmission capability and scheduling. In general, Ontario inter-ties, on a theoretical basis and subject to system conditions, have an import capacity of 4 TW which represents the ability to import approximately 26 TWh of electricity annually and an export capacity of 4.2 TW which represents the ability to export approximately 30 TWh of electricity annually.

Before Market Opening, OPG sold a portion of its energy production into interconnected markets, with a majority of these sales to the northeast and midwest regions of the United States. The level of these sales varied from year to year from a high of 12.6 TWh in 1994 to a low of 3.0 TWh in 1998, with average sales of 3.9 TWh per year in the years 1997 to 2001. Since Market Opening, OPG has been in competition with other market participants to buy or sell energy in and out of Ontario. Over the 2002 and 2003 period, average sales by OPG out of Ontario into the interconnected markets were 2.4 TWh while purchases by OPG out of the interconnected markets into Ontario were 2.6 TWh.

OPG's Market Activities

OPG must offer its production into the IMO-administered real time energy market, or spot market, in order to be dispatched by the IMO. This does not however apply to the small portion of the OPG's generation that is connected to a distributor, which OPG sells directly to the distributor. OPG also offers financial risk management products directly to end-users, as well as to other wholesale parties in Ontario through bilateral contracts. In addition, OPG and the IMO have entered into agreements for the supply of certain contracted ancillary services by OPG, including certified black start facilities, automatic generation control and reactive support/voltage control service.

As most of OPG's energy production is offered into the IMO-administered spot market in order to be available to be dispatched at the spot market prices, the largest part of OPG's revenue is derived from this source, although the price that OPG receives for the majority of the electricity that OPG generates is subject to the Market Power Mitigation Agreement rebate or derivative contracts and is thereby hedged, fixing the price received by OPG for the portion of OPG generation that is hedged. OPG also buys energy from and sells energy into other markets, such as the NYISO, depending on market conditions.

OPG has developed and markets customer focused financial products and energy-related services to Ontario industrial and commercial customers. Specifically, a portfolio of risk management products and supporting services for bilateral transactions, such as forwards, swaps, billing, reporting and verification services, Green Power and energy management products like EnVision, which permits customers to measure and manage energy use, have been developed to meet customers' needs. New information systems and enhanced or redesigned business processes and operations, such as energy trading and risk management operations have been implemented to support these activities.

In Ontario, IMO market participants have the option of having the IMO adjust their settlements to reflect the derivative contracts, by registering certain information about such contracts with the IMO, in which event the Market Rules with respect to 'physical bilateral contracts' are applicable. Non-IMO participants will settle directly with retailers or with distributors providing billing services for retailers.

The introduction of Bill 210 in December 2002 and subsequent regulatory changes reduced the size of the competitive market for electricity in Ontario. Retailers and generators of electricity that sell derivative electricity products in the market, including OPG, were impacted as it reduced the size of their customer base and created uncertainty about the future of the Ontario electricity market. The various changes that are to be made to the operation of the Ontario market and OPG's role in it could affect the nature and extend of the OPG's continued involvement in Ontario's electricity market.

OPG's principal customers in the interconnected markets are U.S.-based investor-owned utilities as well as wholesale market participants active in the regions around Ontario that purchase and sell power on a wholesale basis. Over the past 24 months, the wholesale markets for electricity have seen reduced liquidity arising from the various events that have disrupted or otherwise impacted the markets.

With respect to transactions in the U.S. interconnected markets, OPG is a full participant in the competitive wholesale power market administered by the NYISO and has been actively selling and purchasing energy in the NYISO day ahead and hourly markets since November 1999. OPG is also a member of the Midwest Independent System Operator (MISO) and is entitled to purchase transmission services in that market area.

The Market Rules require parties wishing to export electricity from Ontario to purchase energy from the Ontario spot market in order to sell it to export customers. The OEB has ruled that such export transactions should be charged a fixed transmission usage fee of $1/MWh, in addition to applicable IMO fees and uplift charges (including congestion charges internal to Ontario), all of which in general are expected to aggregate approximately $6/MWh (although it may be higher or lower in any given hour). Market participants can trade transmission rights to provide a hedge against the possibility that there is congestion when importing and exporting electricity. See "*Background – Evolution of Ontario's Competitive Electricity Market*".

The total amount of electricity that was generated within Ontario in 2003 by all generators was approximately 147.5 TWh. Approximately 10.4 TWh of electricity was imported into Ontario and 6.2 TWh was exported in 2003. These transactions allowed Ontario's consumption of 151.7 TWh of electricity to be met. The total transmission and distribution losses associated with delivery of this electricity to Ontario customers was approximately 6.4%, or approximately 9.7 TWh.

Generation Operations

Overview

OPG's portfolio of generating facilities as of December 31, 2003 consisted of 22,777 MW of net in-service capacity comprised of 6,956 MW of hydroelectric and wind capacity, 9,718 MW of fossil capacity and 6,103 MW of nuclear capacity (excluding the facilities leased to Bruce Power), plus further nuclear installed capacity of 1,545 MW that is currently laid up. This represents approximately 30%, 43% and 27%, respectively, of OPG's net in-service capacity. OPG's nuclear stations and some hydroelectric generating plants are used primarily to provide base load capacity as they have very low marginal operating costs and, in the case of nuclear plants, are not designed for frequent variations in production level to meet peaking demand. Hydroelectric and fossil plants provide the bulk of OPG's intermediate capacity and peaking capacity.

Under the terms of its generation licence, OPG was mandated to decontrol at least 4,000 MW of fossil net generating capacity within 42 months after Market Opening (1,000 MW of which can be substituted with hydroelectric net generating capacity) and to reduce its effective control over generation capacity in Ontario to 35% or less of the electricity supply options in the Ontario market within 10 years of Market Opening. To meet these requirements, OPG leased the Bruce A and B nuclear generating stations to Bruce Power effective May 2001 and sold the Mississagi hydroelectric plants (488 MW) to Mississagi Power Trust effective May 2002. In 2003, the Province stated that there will be no further sale of publicly owned generation assets and therefore OPG is not undertaking further decontrol initiatives and is anticipating amendments to these terms of OPG's generation licence.

Hydroelectric Operations

Hydroelectric generating stations use the potential energy of water to drive hydraulic turbines that generate electricity. OPG's hydroelectric stations provide one of OPG's competitive advantages: a reliable, low-cost source of renewable energy that is air emission-free. Through significant capital reinvestment, station automation, efficiency improvements and effective plant maintenance, OPG's hydroelectric plants have low operating and maintenance costs.

Generating Facilities

Generally, hydroelectric stations are grouped geographically and are operated on a river system basis rather than as stand-alone units. OPG's 65 hydroelectric generating stations (which include 29 green energy stations), comprising 6,949 MW of capacity, and associated 232 dams are located on 26 river systems in Ontario.

Five Year Hydroelectric Capability, Capacity and Generation

	1999	2000	2001	2002	2003
Capability Factor (%)	91	92	93	92.6	93.6
Net Capacity Factor (%)	52.9	54	53	53.7	53.2
Net Energy (TWh)	33.6	34.0	33.7	34.3	32.4

Capacity factor and energy statistics for hydroelectric facilities depend primarily upon the availability of water, which is affected by the amount of precipitation and evaporation. In 2000 and 2002, annual production was near historic median production levels. The lower than normal production and capacity factors that occurred in 1999, 2001, and 2003 were due primarily to unusually low water availability resulting from greater than normal evaporation and lower than normal precipitation. In 2003, water levels were unusually low until the fall, when increased precipitation resulted in increased hydroelectric production. The net hydroelectric production for 2003 was, therefore, relatively low.

A significant portion of OPG's hydroelectric production is produced at OPG's three largest stations located on the Niagara and St. Lawrence Rivers representing 43% of total hydroelectric capacity and 52% of hydroelectric energy production in 2003. In 2003, the two Sir Adam Beck stations on the Niagara River provided 1,973 MW of capacity, representing approximately 28% of OPG's hydroelectric capacity, and 10.9 TWh of energy production, representing approximately 33% of OPG's hydroelectric energy produced. On the St. Lawrence River, the R.H. Saunders station provided 1,045 MW of capacity, or 15% of hydroelectric capacity, and 6.4 TWh, or 19% of hydroelectric energy produced in 2003.

Summary of Hydroelectric Generating Facilities and Performance (2003)

River System	Generating Station	Number of In-Service Units	Net In-Service Capacity (MW)(1)	% of Hydro-electric Capacity(1)	Net Energy (TWh)(1)	% of Hydro-electric Net Energy(1)	Original Unit In-Service Dates
Niagara Region							
	Sir Adam Beck I	10	497.8	7.2%	1.5	4.5%	1922 – 1930
	Sir Adam Beck II	16	1,475.0	21.2%	9.4	28.5%	1954 – 1958
	Sir Adam Beck PGS(2)	6	174.0	2.5%	(0.1)	(0.3%)	1957 – 1958
	DeCew Falls I and II	6	166.8	2.4%	1.2	3.6%	1898 – 1948
	Ontario Power(3)	0	0	0.0%	0.0	0.0%	1905 – 1912
St. Lawrence River							
	R.H. Saunders	16	1,045.0	15.0%	6.4	19.4%	1958 – 1959
Ottawa River							
	Otto Holden	8	242.8	3.5%	1.1	3.3%	1952 – 1953
	Chenaux	8	143.7	2.1%	0.7	2.1%	1950 – 1951
	Chats Falls(4)	4	96.0	1.4%	0.5	1.5%	1931 – 1932
	Des Joachims	8	428.8	6.2%	2.2	6.7%	1950 – 1951
Madawaska River		15	614.6	8.8%	1.0	3.0%	1917 – 1977
Abitibi River		9	501.4	7.2%	2.3	7.0%	1933 – 1963
Mattagami River		19	494.9	7.1%	2.6	7.9%	1911 – 1966
Other Rivers		115	1,068	15.4%	4.2	12.7%	1900 – 1993
Subtotal(1)		240	6,949(6)	100%	33.0	100%	
Water Transfers, Unit Rentals and Other(5)					(0.6)		
Total (Net of Transfers)(6)		240	6,949(6)	100%	32.4		

Notes:

(1) Capacity and production information is provided as at or for the year ended December 31, 2003. Net energy is the energy produced by the station less energy consumed by the station.

(2) During off peak periods reversible pump-turbine units at this station operate to pump water for storage in an elevated reservoir. During on peak period's water from the reservoir is run through the pump-turbine units to generate electricity for sale at higher prices. The outflow from the station rejoins the canal which supplies the main generating stations downstream.

(3) The Ontario Power station was removed from continuous service in 1999 as a result of the sale of the site on which the station's power distribution facilities were located. No decision has been made regarding the reactivation of this station to full service.

(4) Chats Falls is an eight-unit station, with four units owned by OPG and four units owned by Hydro-Québec. OPG operates and maintains the station, with costs shared equally with Hydro-Québec. Figures reflect OPG's share of total capacity and net energy.

(5) Hydroelectric generation in 2003 is shown net of the impact of various agreements relating to (i) the diversion of water between Ontario and each of Manitoba and Québec and (ii) agreements with the New York Power Authority regarding rental of generation facilities, which were 0.6 TWh in the aggregate. This also includes adjustments for energy flows into Québec.

(6) Reported net in-service capacity has increased by 26 MW in 2003 to reflect hydroelectric upgrades during 2003.

OPG's hydroelectric generating stations range in age from 10 to over 100 years and are, on average, the oldest assets in its power generation portfolio. Although there is a link between the age of a facility and the capital investment required to maintain that facility, age does not establish an upper limit on the expected useful life of hydroelectric facilities, as regular maintenance and the replacement of specific components typically extend hydroelectric station service life for very long periods.

Facility Planning

OPG employs a portfolio approach to facility planning and maintenance and has grouped its 65 hydroelectric plants into five asset classes which have similar characteristics. Condition assessments are performed to determine future expenditures for each facility, followed by facility life cycle plans (on an as-needed basis). This planning approach is designed to identify necessary capital, operating and maintenance expenditures for each facility in order to prioritize and optimize facility investment within constraints imposed by technical, financial and regulatory requirements and system conditions. Outages are scheduled so as to minimize production losses due to unutilized water and to ensure unit availability during high water availability and market demand.

In the early 1990's, OPG began installing and replacing equipment that enables the remote control and monitoring of OPG's hydroelectric generating facilities. These modifications were designed to increase the efficiency of hydroelectric operations by reducing the number of staffed control rooms from 18 to eight, reducing control system failures and increasing the amount of information available for production planning. OPG now controls all of its hydroelectric generating stations from eight control centres. Work is underway to automate the Chats Falls Generating station on the Ottawa River so that it will no longer require a separate control centre. The automation project is expected to be completed in 2004 and will reduce the number of control centres from eight to seven. Measures have been taken to ensure safety is not compromised. See " *- Health and Safety".*

Since 1990, OPG has refurbished and upgraded several of its hydroelectric facilities which has helped increase its hydroelectric capacity. This reinvestment program is continuing, with approximately $270 million expected to be spent over the next five years.

Water Payments

Hydroelectric generation requires ongoing access to an adequate water supply. OPG's rights to use the water at its hydroelectric stations are established through various international treaties, federal and provincial legislation and the common law. Other related operating rights are contained in leases, licences and agreements with the Federal Government, the Province, neighbouring provinces, municipalities, other utilities and other water users. See "*- Regulation – Regulation of Water Rights*".

OPG makes payments for the use of Crown lands. These consist of gross revenue charges – *see* "*- Relationship with the Province and Others – Special Charges on Hydroelectric Generating Stations*", calculated based on electricity produced at the relevant facility that results from the use of water. Most of OPG's hydroelectric stations pay gross revenue charges. Other stations are covered by separate agreements with various parties with payments made to the various parties having jurisdiction over those stations according to the terms specified in such agreements. The Federal Government receives such payments for stations on Federal canals and waterways; the St. Lawrence Seaway Management Corporation receives lease payments in respect of water transported through the Welland Canal; and the Government of Québec receives payment for sites that span the Ottawa River. OPG has ten stations for which no such payments are made, as there are no water power leases related to these stations. OPG's aggregate water-related payments including the gross revenue charges for 2003 were approximately $120 million for all of its hydroelectric stations. Of this amount, approximately $109 million is the portion paid under the gross revenue charge regime. The remaining balance of $11 million is for payments made to various agencies, including the Federal Government and the Province of Québec.

Water Management

The physical availability of water is affected by variations in precipitation and evaporation. OPG uses hydrological and meteorological data to manage head, flow and water storage and to schedule water use in a manner which minimizes unutilized water flow. OPG's water management strategy is to optimize available water while meeting legal, environmental and operational requirements. Safety requirements are also an important aspect of water management. See "*Business of OPG – Health and Safety – Public Safety*".

Dam Safety Program

OPG operates at a total of 240 dams; 232 dams in connection with hydroelectric generation and eight dams associated with the operation of its fossil generating stations. OPG's dams are operated and maintained in a manner that meets all regulatory requirements, or in the absence of regulations the safety guidelines published by the Canadian Dam Association. The OPG Board of Directors receives an annual report on Dam and Public Safety, as well as regular updates on the status of the program.

In 1986, OPG voluntarily established a dam safety program designed to ensure the safe and reliable operation of its dams and related facilities. OPG is one of the first dam owners in Canada to have developed and implemented a dam safety program. The dam safety program requires regular monitoring and inspections, maintenance and dam improvements where necessary. A review conducted by the Association of State Dam Safety Officials in 1997 concluded that OPG's program is effective, well-managed and contains all necessary elements. Approximately $91.6 million has been spent since 1988 on dam improvements and OPG plans to spend approximately $64 million over the next five years on upgrades and major maintenance as part of its dam safety program.

The Ministry of Natural Resources (Ontario) (the "MNR") has announced its intention to implement dam safety regulations under the *Lakes and Rivers Improvement Act*. In September 1999, the MNR released a draft of its proposals for comments. Discussions regarding these proposals have taken place between MNR staff and various stakeholders, including OPG. The proposals have changed significantly since 1999 and the MNR is still evaluating and amending them. It is difficult to determine the specific impact of these proposed regulations on OPG. If the proposals were enacted as currently drafted, OPG would need to seek alternate methods to satisfy the MNR. This is in part because the proposals include classification and design flood criteria that are different from the Canadian Dam Association criteria used by OPG.

The MNR draft dam safety regulations do however include a provision which will allow owners of existing dams to avoid physically upgrading dams that do not strictly meet the requirements of the new regulation. The proposed regulations address this issue by allowing owners of dams to submit a "Dam Safety Management Plan" to the MNR which would include measures to enhance safety by means other than full structural upgrades. In some instances the option would be significantly less costly than strict compliance with the proposed design flood criteria.

The status that the OPG Dam Safety Program has achieved in the industry is expected to allow OPG the option of submitting Dam Safety Management Plans as a means of managing any residual risks associated with the operation of the structures. Acceptance by the MNR of Dam Safety Management Plans will be subjective and can only be addressed on a case-by-case basis. OPG expects, however, that in most cases it will be able to develop Dam Safety Management Plans that will be acceptable to the MNR.

One aspect of the proposed MNR Dam Safety Regulations which has received considerable attention since 2002 is the component covering public safety around dams. OPG has been extensively consulted on the early drafts of these regulations. Though the MNR has significantly increased the requirements in the area of public safety from the initial proposal, OPG would be in compliance. A review of OPG's practices in the area of public safety around waterways which was completed in 2003 concluded that the aspects have been fully integrated into the managed systems used in the operation of OPG's facilities.

Potential Expansion and Development at the Beck

OPG is not able to use all of the water available to it at Niagara. OPG mitigates the impact of this situation through a unit rental arrangement with the New York Power Authority ("NYPA") pursuant to which, under certain conditions, OPG rents generating units of the NYPA that are surplus to NYPA's needs at the time, to maximize generation from OPG's share of the Niagara River water.

OPG has evaluated a number of alternatives to maximize its use of its share of the water on the Niagara River. One such option would consist of two new tunnels extending from the Niagara River upstream of Niagara Falls to the Sir Adam Beck site, a new powerhouse and associated transmission facilities.

The first part of the proposed project, construction of one of the tunnels, would take approximately four years to complete. While this part of the project would provide a nominal increase in capacity due to an increase in head on the existing plants, no additional capacity (units) would be built. This would also result in OPG being able to produce more electricity from its existing Sir Adam Beck generating facilities through the use of additional water. It would also permit OPG to repair the existing canal without having to schedule a planned outage at the station. The Province has not yet informed OPG what role it sees for OPG with regard to this project.

The construction of a second new tunnel and a new generating station, the second part of the project, would require approximately an additional five years to complete and is estimated to cost in excess of $1.2 billion. The

Ministry of Energy has undertaken a study to assess all aspects of this project. This study was anticipated to be completed during the first half of 2004.

Fossil Operations

Fossil generating stations burn coal, oil or natural gas to heat water and create steam, which is used to drive turbines that generate electricity. OPG's fossil stations are currently an important component of OPG's overall portfolio. Fossil stations provide a flexible source of energy, as the stations may be taken on-line and off-line relatively quickly and without significant additional cost. Fossil stations may be deployed during periods of intermediate and peak demand or as a base load energy source to accommodate variations in the balance of the generating portfolio due to either planned or unplanned outages within the fleet.

As noted above, the Province has indicated that it intends to have OPG's coal-fired stations shut down by 2007. As a result, OPG will be reviewing and potentially revising its financial and operating plan for the coal plants as the specifics about the shut down are clarified.

One of the major concerns relating to coal-fired generating stations is that they contribute to pollution in their air-shed. Through major investment in pollution control technologies, emission rates of nitrogen oxide ("NO_x") and sulphur dioxide ("SO_2") from OPG's fossil plants have been substantially reduced. Continued investment by OPG to meet prospective Ontario and U.S. regulatory standards could bring further reductions in emission rates and in actual emissions. Regulations establish emission caps for OPG's fossil stations and limit SO_2 and NO_x emissions. Any decision by OPG to invest in additional control technologies will depend on the specific schedule to phase out coal fuelled electricity production.

Generating Facilities

OPG currently owns and operates six fossil stations. A total of 23 fossil generating units were in-service during 2003 with a combined net in-service capacity of approximately 9,718 MW, representing approximately 43% of OPG's total in-service capacity in 2003 of 22,777 MW. Coal-fired generating units located at Nanticoke, Lambton, Lakeview, Thunder Bay and Atikokan account for approximately 7,578 MW of in-service capacity. Dual-fuelled (i.e. capable of burning either oil or natural gas) generating units at Lennox account for approximately 2,140 MW of in-service capacity.

Five Year Fossil Capability, Capacity and Generation

	1999	2000	2001	2002	2003
Capability Factor (%)	68	76	71	76	71.4
Net Capacity Factor (%)					
Coal	51	62	56	54	54.5
Oil/Gas	12.3	6.4	16.7	16	14.9
Net Energy (TWh)	36.1	42.4	40.2	39.6	39.0

The increase in fossil capacity factors and total energy produced between 1999 and 2000 was due in part to increased coal-fired generation being required to compensate for declines in nuclear generation resulting from the lay-up of the Pickering A units under the 1997 Nuclear Recovery Plan. Two of the four units at Lambton, which have been equipped with scrubbers, and the eight units at Nanticoke, have provided most of this additional fossil generation. In order to meet the increased production demands on fossil generating units and still meet all regulatory requirements, a number of emission reduction initiatives were implemented. These included increasing the use of low-sulphur fuels and capital investments to reduce NO_x emission rates. For example, in order to reduce OPG's NO_x emission rates, approximately $90 million was spent between 1999 and 2001 on completing the conversion of units at Lennox to gas, the installation of low NO_x burners at Lambton, Nanticoke and Lakeview and the use of computer controls to reduce NO_x emission rates at Lambton and Lakeview. In 2003, OPG completed the installation of selective catalytic reduction equipment to significantly reduce NO_x emission rates on two of eight units at the Nanticoke generating station and on two of four units at the Lambton generating station, at a cost of approximately $262 million. See "*– Environmental Matters – Management of Air Emissions – Fossil Operations*".

Summary of Fossil Generating Facilities and Performance (2003)

Station	No. of In-Service Units	Net In-Service Capacity (MW)(1)	% of Fossil Capacity(1)	Net Energy (TWh)(1)	% of Fossil Net Energy(1)	Original Unit In-Service Date(s)	Original Retirement Date	Assumed Retirement Date(2)
Nanticoke(3)	8	3,938	41	20.4	52.3	1973-1978	2015	2007
Lambton(3)	4	1,975	20	10.6	27.2	1969-1970	2010-2020	2007
Thunder Bay(3)....	2	310	3	1.5	3.8	1981-1982	2021	2007
Atikokan(3)..........	1	215	2	0.9	2.4	1985	2025	2007
Lakeview(3) (4)	4	1,140	12	2.8	7.2	1962-1969	2005	2005
Lennox(5)............	4	2,140	22	2.8	7.1	1976-1977	2016	2016
Total..................	23	9,718	100	39.0	100			

Notes:

(1) Capacity and production information is provided as at or for the year ended December 31, 2003. Net energy is the energy produced by the station less energy consumed by the station.

(2) The service lives for OPG's coal-fired generating stations (except Lakeview) were previously estimated as follows: Lambton – 2010 to 2020 (units 3 and 4 had an estimated retirement date that was 10 years longer than units 1 and 2 as a result of extensive plant rehabilitation); Nanticoke – 2015; Thunder Bay – 2021; and Atikokan – 2025. These previous estimates were based on the average in-service date of units at the station and an estimated service life of 40 years (except units 3 and 4 at Lambton, as described above). Based on the Province's commitment to close OPG's coal-fired generating stations by 2007, the Nanticoke, Lambton, Thunder Bay and Atikokan coal-fired generating stations would be removed from service before the end of their previously estimated useful lives and the above table therefore reflects this Provincial commitment. The termination of operating cash flows from these stations after 2007 resulted in a pre tax impairment loss of $576 million being recognized in 2003.

(3) All units are coal-fired.

(4) Four additional generating units at Lakeview representing approximately 1,100 MW of power capacity were permanently taken out of service in 1992 as surplus capacity. A Provincial regulation requires Lakeview to cease burning coal by April 2005.

(5) Lennox units are dual-fuelled (oil/natural gas).

Facility Planning

OPG's facility planning approach is designed to identify necessary capital, operating and maintenance expenditures for each facility in order to optimize returns from plant reinvestment within constraints imposed by technical, financial and system requirements as well as regulatory and voluntary emissions limits.

Large temperature and pressure variations experienced during cycling operation (i.e. stopping and starting the units frequently) of fossil units to meet system peaks cause more mechanical wear than continuous operation. For example, between 1995 and 1997 OPG's fossil stations were used primarily for peaking loads. There was, however, an excess of capacity in Ontario, so forced outages did not have a significant impact on OPG's ability to provide capacity to meet Ontario demand. As a result of the lower economic impact of outages, OPG generally focused on corrective rather than preventative maintenance for these stations, thereby avoiding extraordinary costs that OPG might otherwise have incurred to reduce the duration of outages. With increased usage of the fossil generating stations due in part to the lay-up of the Pickering A and Bruce A nuclear generating stations, increasing fossil capability has been an OPG priority, resulting in additional preventative maintenance activities and reduced outage periods. In light of the recent announcements by the Province that it intends to require that OPG shut down its coal-fired generating stations, OPG is carefully considering what expenditures are appropriate with respect to maintenance of its coal-fired generating stations. Notwithstanding that the Province has announced that these stations will be shut down, OPG's first priority is to make appropriate investments to ensure that it can safely operate its coal-fired generating stations.

OPG has recognized, and carries on its balance sheet, a liability to cover future expenditures to decommission and dismantle each of its fossil stations. This provision is valued at approximately $146 million on a net present value basis as at December 31, 2003 and is not currently funded. Approximately $49 million of this decommissioning liability is associated with two stations, Nanticoke and Lambton, and $40 million is attributed to OPG's Lakeview station.

Occupational Safety

OPG was charged under the *Occupational Health and Safety Act* (Ontario) ("OHSA"), in connection with the employee fatality that occurred on October 15, 2002, while the floor around the coal conveyor belt at the Nanticoke generating station was being cleaned. In October, 2003, OPG pleaded guilty to failing to ensure that a conveyor was guarded to protect a worker from pinch-point hazards, as prescribed by the OHSA Regulations, and was fined $350,000.

Immediately following the fatality, OPG initiated a review of the operation and maintenance of its coal handling systems. This review was completed in April, 2003, and resulted in the adoption by OPG of more detailed operating standards, together with action plans for implementing and complying with the regulatory standards.

Fossil Fuel Procurement

Coal is the fuel used at all of OPG's fossil generating stations except Lennox. Fuel and related transportation costs in 2003 accounted for approximately 77% of the total production cost of OPG's fossil generation. In 2003, OPG's total fossil fuel and related transportation costs amounted to $1,189 million, 77% of which was for coal. Approximately 83% of these costs in 2003 represented purchases denominated in U.S. dollars.

OPG's coal purchases are made pursuant to a variety of short and medium term contracts. The price of coal started to increase in the last quarter of 2003. This is not expected to materially impact the amount that OPG pays for coal purchases in 2004, as OPG has entered into coal purchase contracts that are expected to fulfil most of OPG's 2004 coal requirements. If these higher prices continue, it is anticipated that OPG's average cost of coal will increase in the future, potentially significantly.

Approximately 90% of the coal used at OPG's fossil stations in 2003 was shipped by way of the Great Lakes. OPG maintains a seasonal inventory of coal at each of its coal-fired stations that is expected to be sufficient to meet forecast energy requirements during the winter months, typically from the end of December to the end of March, when Great Lakes shipping lanes are closed.

OPG's coal costs are affected by various factors including the cost of transporting coal from the eastern and western United States and western Canada, the sulphur content of coals and by choices made in balancing supplier diversity, contractual flexibility, fuel type and fuel quality. OPG blends coal with a range of sulphur contents for use in units that are not equipped with desulphurization scrubbers.

Natural gas and oil are used at the Lennox generating station. Approximately 20% of the volume of natural gas purchased in 2003 for Lennox was purchased pursuant to a long-term supply contract. This supply is shipped by pipeline from Alberta to Lennox. The rest of the natural gas requirements are fulfilled by spot market purchases in Ontario. In 2003, OPG's total purchases of natural gas for Lennox cost approximately $152 million.

The residual fuel oil for the Lennox generating station is purchased through short-term "spot" purchases for volumes of typically 40,000 to 80,000 cubic metres (250,000 to 500,000 barrels) at a time. OPG does not currently have any long-term oil purchase agreements in place. This is in part because Lennox is a peaking station and therefore the production requirements are highly variable and the fuel requirements can adequately be covered by the plant's dual fuel capability. OPG's standard fuel specification for Lennox is for low sulphur oil (under 0.7% sulphur content). Pricing is typically tied to published oil price indices based upon delivery at New York Harbour for the quality of oil purchased. Transportation of residual fuel oil to Lennox is accomplished through leased rail cars, from terminals in either Québec or New York. In 2003, these residual fuel oil purchases cost approximately $131 million.

Brighton Beach Venture

OPG has a 49.95% partnership interest in Brighton Beach Power L.P. ("Brighton Beach"), a limited partnership formed with ATCO Power Canada Ltd. (39.96%), ATCO Resources Ltd. (9.99%) and, the general partner of the partnership, Brighton Beach Power Ltd. (0.1%). The shareholders of Brighton Beach Power Ltd. are OPG (50%), ATCO Power Canada Ltd. (40%) and ATCO Resources Ltd. (10%). Brighton Beach is building a 580 MW combined cycle gas turbine electricity generating facility on the site of the former J.C. Keith Generating Station site in Windsor, Ontario. In September 2002, Brighton Beach completed a $403 million private bond and term debt financing for its facility. Construction of the project began in the summer of 2002. The plant is scheduled to be in-service during the summer of 2004, however, it is expected that the cost of the project will exceed its initial estimate. Brighton Beach has entered into a tolling arrangement with Coral Energy Canada Inc. ("Coral") under which Coral will own and trade the electricity produced by the facility in return for the supply of gas and the fees payable under a tolling agreement. Coral's financial obligations are guaranteed by Coral Energy Holding L.P. ("Coral L.P.") and Coral L.P.'s obligations are in turn guaranteed by Shell Oil Company.

Portlands Energy Centre Venture

OPG has a 49.95% partnership interest in Portlands Energy Centre L.P. ("Portlands"), a limited partnership formed with TransCanada Energy Ltd. (49.95%) and, the general partner of the partnership, Portlands Energy Centre Inc. (0.1%). The shareholders of Portlands Energy Centre Inc. are OPG (50%) and TransCanada Energy Ltd. (50%). Portlands will assess the viability of developing a natural gas-fuelled energy centre in the port area of downtown Toronto. An Environmental Review report was submitted to the Ministry of Environment in November 2003. If environmental approvals are granted, all applicable agreements are satisfactorily completed and the project proceeds, the plan contemplates that a 550 MW natural gas-fired, combined-cycle, co-generation facility would be constructed. Portlands and Enwave District Energy Limited are in discussions that could see Portlands supply steam to Enwave's district heating system.

Effective Generation Limits and Air Emissions

Air Emissions Regulation

There are two main regulations that limit OPG's air emissions. Under Ontario Regulation 153/99, SO_2 and NO_x emissions from OPG's six major fossil stations (Lakeview, Lambton, Nanticoke, Lennox, Thunder Bay and Atikokan generating stations) are subject to an annual aggregate cap of 215 Gg. SO_2 emissions are also capped separately under this regulation at 175 Gg annually. Under a separate regulation, Lakeview was limited to 3.9 Gg NO_x in 2003 and in 2004.

Layered on top of the limits described above, Ontario Regulation 397/01, the "Emissions Trading Regulation", imposes additional reductions of SO_2 and NO_x emissions from the Ontario electricity sector beginning in 2002, as well as providing a framework for emissions trading.

Ontario Regulation 397/01 requires OPG to demonstrate annually that its SO_2 and NO_x emissions do not exceed the limits set for SO_2 and NO_x emissions ("allowances") in the Regulation. Emission Reduction Credits ("ERCs") can be used to meet the limits prescribed. However, the amount of SO_2 ERCs used annually cannot exceed 10% of the SO_2 allowances provided. Similarly, the amount of NO_x ERCs used annually cannot exceed 33% of the NO_x allowances provided. Unused allowances and ERCs may be banked for future use, or traded.

OPG was allowed to emit, or in other words, received 153.5 Gg of SO_2 allowances and 35 Gg of NO_x allowances annually for distribution across the six major fossil stations in each of 2002 and 2003. For each of these years, the Province also set aside an additional 4 Gg of SO_2 allowances and 1 Gg of NO_x allowances (the "set-aside" allowances) to be allocated to green power and conservation projects. The unclaimed set-aside allowances were transferred to OPG in 2002 and 2003. See "*Five Year Fossil Production and Air Emissions*" table below.

Beginning in 2004, the Emissions Trading Regulation applies to the entire electricity sector in Ontario, rather than just OPG. This means the annual allowances previously allocated to OPG (153.5 Gg SO_2 and 35 Gg NO_x) are to be allocated across the electricity sector in 2004, with available allowances decreasing in future years, as shown in the chart below. The allocation for OPG's facilities for 2004 is 152.9 Gg $SO_2$and 25 Gg NO_x in 2004 (including Lakeview).

Ontario – Electricity Sector SO_2 and NO_x Allowances

	SO_2 Allowances (Gg)		NO_X Allowances (Gg)			
Year	OPG Facilities	Total Ontario Electricity Sector	Lakeview GS	Other OPG Facilities(1)	Other Fossil Generation(1)	Total Ontario Electricity Sector
2002	153.5		3.9	31.1	N/A(2)	35.0
2003	153.5		3.9	31.1	N/A(2)	35.0
2004	152.9	153.5	3.9	21.1	10.0	35.0
2005		153.5	1.3(3)	21.1	12.6	35.0
2006		153.5		21.1	13.9	35.0
2007		127.0		17.0(4)	10.0	27.0

Notes:

(1) The allowances for OPG's Atikokan, Lambton, Lennox, Nanticoke and Thunder Bay facilities are expressed on an aggregate basis.

(2) No annual NO_X allowances limits. All Other Fossil Generation must respect other environmental regulations (e.g. Certificates of Approval) under the EPA.

(3) As of May 1, 2005, NO_X allowances from Lakeview will be part of the allowances allocated to Other Fossil Generation.

(4) OPG allowances in 2007 are based on 15.5 Gg in Pollution Emission Management Area (defined in O. Reg. 397/01 and includes the southern Ontario air shed) plus 1.5 Gg outside Pollution Emission Management Area, as specified in O. Reg. 397/01.

Fossil Generation and Air Emissions

In 2003, OPG's fossil facilities generated 39.0 TWh of energy, resulting in 39.0 Gg of NO_x emissions and 157.8 Gg of SO_2 emissions. OPG has met the requirements of O. Reg. 153/99, and is in possession of the required allowances and ERCs to satisfy the requirements of O. Reg. 397/01 for 2003.

The following table sets out certain air emissions from OPG's fossil generating facilities for the past five years, with reference to applicable regulatory limits or voluntary limits, SO_2 and NO_x allowances, ERCs and total fossil energy production.

Five Year Fossil Production and Air Emissions

	1999	2000	2001	2002	2003
Net energy (TWh)[1]	36.1	42.4	40.2	39.6	39.0
SO_2 emissions (Gg)					
OPG emissions	142.1	164.1	149.0	147.2	157.8
Allowance Allocation[2]				153.5	153.5
Set Aside Allowances				3.9	3.9
Carry Forward Allowances					19.3
Total Allowance Allocation[9]				157.4	176.8
Total Allowances Retired[8]				138.1	157.8
Carry Forward ERCs					0
Emission Reduction Credits Retired				9.1[7]	0
Total Allowances and Credits Retired				147.2	157.8
Regulatory Limit [3]	175.0	175.0	175.0	175.0	175.0
NO_x emissions (Gg)					
OPG emissions	51.4	50.5	44.6	42.3	39.0
Allowance Allocation[2]				35.0	35.0
Set Aside Allowances[9]				0.9	0.9
Carry Forward Allowances					4.2
Total Allowance Allocation[9]				35.9	40.1
Total Allowances Retired				31.8	34.0
Carry Forward ERCs[7]					6.9
Emission Reduction Credits Retired	N/A	12.5	6.6	10.5[7]	5.0[7]
Total Allowances and Credits Retired	N/A	12.5	6.6	42.3	39.0
Regulatory Limit	See Note (8)	See Note (3) and (4)	See Note (3) and (4)	See Note (3)	See Note (3)
Total Acid Gas Emissions (Gg)	193.5	214.6	193.6	189.5	196.8
CO_2 emissions (Tg)					
OPG emissions gross	32.2	38.5	37.0	36.72	36.5+ nuclear
Emission reduction credits	N/A	12.5	See Note (6)	See Note (6)	See Note (6)
Voluntary Limit (net)[5]	N/A	26.0	26.0	26.0	26.0

Notes:

(1) Net energy is the energy produced by the station less energy consumed by the station.

(2) Started in 2002 under O. Reg. 397/01.

(3) O. Reg. 153/99 continues to apply (in concert with O. Reg. 397/01), meaning that OPG cannot exceed the annual limit of 175 Gg of SO_2 using the combination of allowances and emission reduction credits permitted under O. Reg. 397/01 and cannot exceed the annual limit of 215 Gg of SO_2 and NO_x.

(4) OPG agreed with provincial government agencies to voluntarily cap its NO_x emissions, net of emission reduction credits used, at 38 Gg annually, commencing in 2000.

(5) In 2003 OPG decided to delay further investments in CO_2 emission reduction credits. See *"- Environmental Matters – Management of Air Emissions – Fossil Operations"*.

(6) The timeframe for reconciliation of net CO_2 emissions in the period 2001 to 2007 has been extended to the end of 2010. See "- *Environmental Matters – Management of Air Emissions – Fossil Operations*".

(7) The net emission reduction credits are shown here. The regulation requires that an additional 10% of emission reduction credits be retired for the betterment of the environment.

(8) Retired means used to meet regulatory requirements.

(9) Total allowance allocation includes allowances carried forward from previous year, starting in 2003, one year after O. Reg. 397/01 came into effect.

In order to meet its NO_x emission limits without limiting the amount of electricity that OPG can generate and sell during the year, in 2003 OPG completed the installation of selective catalytic reduction ("SCR") technology on two of eight units at the Nanticoke station and on two of four units at the Lambton station, at a cost of approximately $262 million. In addition, OPG has installed low NO_x burners on all units except Lennox and Thunder Bay. Further, OPG has the flexibility to use emissions trading to meet its regulatory commitments. With the development of an emission reduction trading program, OPG could obtain and use ERCs to offset NO_x emissions to an upper limit of one third above the allowances set out in the Emissions Trading Regulation. It is anticipated that current levels of generation from the fossil plants controlled by OPG could be sustained in the short-term through the use of ERCs.

SO_2 emission rates are directly related to the sulphur content and heat content of the fuel burned. OPG is primarily using higher-cost low sulphur fuels to reduce SO_2 emissions. The conversion to dual-fuel (natural gas and oil) generating ability of four oil-fired units at the Lennox station was completed in 2000 and contributes to the reduction of SO_2 emissions because sulphur is removed from the gas before it arrives at the station. The cost of converting the units to burn gas was about $30 million and the cost of the pipeline to supply the gas was $20 million. OPG installed SO_2 scrubbers on two units at the Lambton station in the mid-1990s, at a cost of approximately $500 million, to reduce the SO_2 content of the flue gas before it is emitted into the atmosphere. Consequently, OPG will be able to meet to meet its regulatory requirements related to SO_2 emissions for the foreseeable future. For further discussion of the regulation of air emissions, see "- *Environmental Matters – Management of Air Emissions – Fossil Operations*".

Nuclear Operations

Nuclear generation harnesses the energy released during controlled nuclear fission reactions to produce steam that is used to drive turbines to generate electricity. Nuclear generation has two main advantages: it is a relatively low marginal-cost production technology and it produces virtually no SO_2, NO_x, CO_2 or mercury. The latter advantage is increasing in significance as governments implement stricter air emission standards.

Nuclear stations have greater operational, maintenance, nuclear waste and decommissioning costs and have greater initial capital development costs than other generation technologies. This reflects the complexity of the technical processes that underlie nuclear power generation and the additional design and safety precautions that are taken to protect the public from potential risks associated with nuclear operations. Offsetting these cost factors is the relatively low cost of nuclear fuel compared with fossil fuel costs. OPG's nuclear fuel is supplied by Canadian-based manufacturers that process uranium ore from both domestic and foreign sources. In general, OPG's nuclear stations have a lower operating cost per megawatt-hour of electricity produced than fossil facilities.

OPG's nuclear generating stations were designed to function primarily as base load facilities. OPG's three in-service nuclear generating stations provided approximately 35% of OPG's total electricity production in 2003 - the Pickering A station has one in-service unit and the Pickering B and Darlington stations each have four in-service units.

Generating Facilities

Energy produced at the nuclear generating stations operated by OPG has declined in absolute terms since 1998, primarily as a result of OPG entering into a long term lease of the Bruce A and Bruce B generating facilities to Bruce Power on May 11, 2001. At the time of the lease, the Bruce A units were laid up and the Bruce B units were producing approximately 20 TWh on an annual basis.

OPG currently owns and operates the Pickering A (one in-service unit and three laid up units), Pickering B (four in-service units) and Darlington (four in-service units) nuclear generating stations. The four Pickering A units were laid up in 1997 as a result of OPG's 1997 Nuclear Recovery Plan. One of these units was restarted in September 2003.

Five Year Nuclear Capability, Capacity and Generation(1)

	1999	2000	2001	2002	2003
Net Capability Factor (%)	81	79	82	86	76
Net Capacity Factor (%)	80	78	81	86	75
Net Energy (TWh)	61.4	59.8	47.7	41.9	37.7

Note:
(1) The information in this table includes statistics applicable to the Bruce B nuclear generating station up to May 11, 2001, the date the Bruce facilities were leased by OPG to Bruce Power.

Summary of Nuclear Generating Facilities and Performance (2003)

Station	No. of In-Service Units	Net In-Service Capacity per Unit (MW)(1)	Net In-Service Capacity (MW)(1)	Capacity Factor(1)	Net Energy (TWh)(1)	% of Nuclear Net Energy(1)	Original Unit In-Service Dates	Estimated Operating Life(2)
Darlington..............	4/4	881	3,524	80.4%	24.9	66	1990-1993	2018-2019
Pickering A(3)..........	1/4(4)	515	515	69.3%	0.8	2	1971-1973	2023(5)
Pickering B	4/4	516	2,064	66.2%	12.0	32	1983-1986	2013-2016
Total	9/12		6,103	75%(6)	37.7	100		

Notes:

(1) Information is provided for the year ended December 31, 2003. Net energy is the energy produced by the station less energy consumed by the station, as measured by the revenue meter.

(2) The estimated operating life of each nuclear generating station is assumed to end when substantial capital expenditures are required to replace life-limiting components such as fuel channels and steam generators, typically after 25 to 30 years of operation. The estimated operating life of Pickering A is expected to be 40 years (see note 5). The operating lives of these stations can be extended with substantial capital expenditures but OPG will incur these expenditures only if justified by prevailing economic, financing and market conditions. See "*Business of OPG - Generation Operations -Nuclear Operations - Operating Life Assessment*".

(3) 2,060 MW of capacity was removed from service in 1997 as a result of the lay-up of Pickering A under OPG's 1997 Nuclear Recovery Plan.

(4) OPG returned Unit 4 at Pickering A to service in September 2003.

(5) For Pickering A Unit 4 (in-service unit) only. Generally, OPG replaced the pressure tubes of Pickering A between 1984 and 1993 after the discovery of a design flaw. Thereafter, OPG extended the operating life estimate for Pickering A to 40 years because of these new pressure tubes and the condition of the existing steam generators.

(6) The percentage represents the average capacity factor for in-service units.

Nuclear Recovery

Optimization of OPG's nuclear generation capacity has been an important part of OPG's strategic plan. OPG's nuclear generating stations performed well after they were initially brought into service. However, over the years, inadequate operational and maintenance practices and the lack of timely investment contributed to declining nuclear production as evidenced by more frequent forced outages and extensions to planned outages.

In early 1997, OPG engaged a team of independent nuclear recovery experts to assess its nuclear operations. This team adopted a methodology developed and used by the United States Nuclear Regulatory Commission to identify fundamental operating problems at U.S. nuclear generating stations in the 1980s.

The team classified OPG's nuclear operations as "minimally acceptable" and noted that the design of the CANDU reactor was not a contributing factor to OPG's declining nuclear performance. They concluded OPG's operational and maintenance activities were below industry standards and its management systems were not capable of ensuring that these activities were being planned and executed in a rigorous and cost-effective manner. The team found an organizational culture not focused on efficient and effective operation. In addition, the team found evidence of deteriorating equipment at each nuclear generating station and concluded that OPG was not repairing equipment promptly enough to prevent further deterioration and that the inspection program for critical components and preventative maintenance programs were inadequate.

In response to this assessment, OPG developed a comprehensive nuclear recovery plan (the "1997 Nuclear Recovery Plan") to improve the operating performance of its nuclear generating stations by 2003. Under the plan, OPG was to standardize its operations and implement initiatives to improve accountability; management and operational control systems; maintenance and inspection programs; regulatory compliance; performance standards and employee training. This recovery plan also required the lay up of the Pickering A units in order to focus qualified personnel and management resources on the recovery efforts on the remaining eight better performing nuclear generating units at the Darlington and Pickering B stations. The plan was aggressive and was seeking to achieve in five years what the U.S. industry took over ten years to achieve. The recovery plans launched in early 1998 initiated specific projects that focused on implementing improved employee training and work management processes along with significant improvements in fire protection, plant configuration management and improved environmental qualification of equipment. It also established processes to enable better monitoring of plant conditions and operational performance. Expenditures related to the 1997 Nuclear Recovery Plan projects during the period from 1997 to 2003 were $1,091 million. In addition, $193 million was expended as part of the Pickering A Return to Service project and has been included in that project's total costs as disclosed in this document. Two significant projects in the recovery plan, fire protection and environmental qualification, are not yet complete and expenditures on these projects are estimated to be $65 million in 2004.

Early in 2003, in response to concerns about the reversal of improving performance at Pickering B and increasing maintenance backlogs at both plants, OPG undertook a reassessment of the nuclear business plan. The underpinning of the 2003 assessment was a detailed review of the material condition risks at Pickering B and Darlington and benchmarking analysis on both staff levels and costs. The assessment concluded that: (i) production expectations laid out in the 1997 Nuclear Recovery Plan were not completely achievable; (ii) the cost and staff level targets were not realistic; (iii) most of the improvement initiatives were not targeted at directly improving material condition and the reinvestment levels were also not realistic to sustain desired operating levels; and (iv) while the implementation of the 1997 Nuclear Recovery Plan did achieve significant success in improving nuclear safety, regulatory compliance, capability factors and lowering unplanned outages, the increasing backlogs and material condition issues were indicators that OPG's units would be unlikely to maintain their current capability factors and achieve the performance status that OPG had expected would result from implementing the 1997 Nuclear Recovery Plan.

The findings from this 2003 reassessment were used to develop the 2004 business plan for OPG's nuclear stations. The business plan focuses on improved material condition, productivity and human performance, with specific funding set aside to be applied towards these areas. It makes provision for increased operating costs and sustaining investments for the future.

One of the key measures used by members of the World Association of Nuclear Operators to assess the relative performance of individual nuclear stations is the Nuclear Performance Index ("NPI"). The NPI quantifies the performance of nuclear generating stations with a weighted series of ten performance indicators, seventy percent related to safety and thirty percent to generation. A perfect score is 100 and is based on performance data that is typically a two-year average, therefore, Pickering A is not included in OPG's statistics. OPG's overall NPI performance in 1997 was 58.0 at which time the average top quartile performance was 89. OPG's performance increased significantly over the 1998 to 2000 period to 83.3 and has remained in that range since, achieving a score of 81.5 in 2003. At the end of 2003 the U.S. top quartile had moved to 99. The primary reason for OPG's poor performance relative to industry top performers is poor generation performance. In 2003, OPG scored 16 out of a possible 30 points in the generation related measures. Nuclear safety performance, on the other hand, has been comparable to industry top performers with OPG scoring about 66 of the 70 points related to safety performance. This is largely attributed to the success experienced in the 1997 Nuclear Recovery Plan's safety related initiatives. The performance of the Darlington station has generally improved more than the Pickering B station, as follows:

- Darlington's NPI performance improved significantly over 1997 to 2003. The four units were performing in the 48 to 62 range in 1997 and have improved to the 92 to 94 range at the end of 2003. Darlington's generation output improved significantly over this period, largely due to a 60 percent reduction in unplanned losses. Darlington largely met the generation and performance expectations as laid out in the 1997 Nuclear Recovery Plan. The improvements in processes and the inspection programs have facilitated the determination of the necessary programs and other courses of action that Darlington must follow in order to sustain and continue to improve this performance. These include understanding and mitigating the generation reliability risks and reducing the maintenance backlogs.

- Pickering B's performance has not improved as planned, largely due to Pickering B being older than Darlington, therefore it was extremely difficult to anticipate and repair the aging components and material condition issues. These issues have manifested themselves in higher unplanned losses and longer planned outages. The NPI for Pickering B in the 1997 period was in the 50 to 58 range for the four units and improved to the 59 to 77 range at the end of 2003, due mainly to improvements in safety.

In 2003, OPG met or exceeded 10 of its 22 key nuclear performance targets, including the targets for nuclear, public, employee and environmental safety, human performance and the cost of operations. The two most significant areas in which targets were not met were generation and the return to service of Pickering A units. Pickering B's 2003 generation was significantly lower than planned (actual of 12.0 TWh compared to a target of 14.62 TWh) due primarily to a high number of unplanned outages in the first half of the year, as a result of material condition issues. Darlington's generation was slightly below target at 24.8 TWh compared to a plan of 25.97 TWh. The delay in returning Pickering A Unit 4 to service resulted in a production of 0.8 TWh compared to a target of 2.0 TWh in 2003.

Operating Life Assessment

The initial estimated operating life for OPG's nuclear generating units was 30 years. OPG undertakes a comprehensive inspection and testing program in order to ascertain the physical condition of its nuclear generating assets. The condition of the major components is assessed using a variety of inspection techniques such as ultrasonic, visual and functional testing. These results provide engineers with an assessment of the condition of such components relative to original design. Repeated inspection or testing during planned outages is used to establish degradation rates. The experience of other nuclear operators is also taken into consideration. This information is used to update the life cycle management plans for major plant components. The life cycle management plans are a key input to OPG's business planning process. OPG's current operating life estimates (see " – *Generating Facilities – chart on Summary of Nuclear Generating Facilities and Performance (2003)*") for its nuclear generating stations are based on the results of this program to date and on the previous operating history of the stations. OPG will continue to analyze information on the physical condition of its nuclear generating stations and develop appropriate operational and maintenance activities.

As a key part of its 1997 Nuclear Recovery Plan, OPG has undertaken an ongoing program to assess the condition of key components of the system including its steam generators, fuel channels and feeder pipes. As a result of these programs, OPG has been better able to quantify equipment degradation status, such as the extent of steam generator tube corrosion, feeder tube wall thinning and pressure tube/calandria tube spacer location and relocation issues. As of December 31, 2003, 87% of OPG's steam generators (with 81% of the tubes) had been inspected and the present condition of these components has been ascertained with a reasonable degree of certainty. On the basis of the steam generator program inspection results, periodic cleaning, repairs and internal modifications have been deemed necessary to slow down the degradation rates and restore unit reliability. OPG is currently implementing comprehensive operation and maintenance life cycle management plans at all operating stations aimed at enabling the steam generators to operate for the expected life of the station. Current estimates of the steam generator life are within the estimated operating lives of the units.

Current inspections in the fuel channel program support the fuel channels lasting until the estimated operating lives for the stations. Maintenance activities at Pickering B to reposition the support springs in the fuel channels started in 2002 and are planned to continue over the next several years to ensure that the end of life projections are achieved. This program is being accelerated as a result of recent inspection results that indicate the hydrogen concentration is higher than predicted. This is not expected to impact the end of life prediction. The modular design of the reactors also allows for replacement of individual channels during planned outages, if required.

Feeder pipes are part of the piping system that carries hot water between the reactor and the steam generators. Thinning of feeder pipes occurs to varying degrees at all of OPG's reactors. This condition is most significant at the Darlington station, but also affects the Pickering A and B stations to a lesser degree. Extensive inspections have been carried out to establish the current condition of the feeder pipes. If the currently observed thinning rate at Darlington continues, this situation may require replacement of significant numbers of feeder pipes before the projected end of life. Mitigation options are under development by OPG which may extend feeder pipe life, reduce the thinning rate, and improve the capability to replace feeders. The results of OPG's inspections indicate that even if such mitigation options are successful in saving 90% of the feeder pipes that are currently at risk, additional expenditures in the range of $50 – 100 million (for four units at Darlington) and one to two months of additional outage time per unit, will still be required over the next decade to deal with thinning feeder pipes. This strategy and its associated costs continue to be reviewed and revised as appropriate.

Cracking of feeder pipes has been experienced at two CANDU plants located outside Ontario. The affected sections of pipe were replaced and the units were returned to service. OPG has not experienced any feeder pipe cracking at any of its nuclear facilities but is carrying out inspections during regularly planned outages. The scale of these inspections has been increased in response to these external events. OPG is also participating in research and development with other CANDU operators to establish the degradation mechanisms.

CANDU Technology

All of OPG's nuclear generating stations use CANDU reactors. CANDU is a pressurized-heavy-water, natural-uranium power reactor first designed in the 1960's by a consortium of Canadian government agencies and private industry. All nuclear reactors in Canada use the CANDU technology. It is also the power-reactor product marketed by Canada abroad. CANDU reactors are currently operating in Ontario, Québec, New Brunswick, Argentina, Romania, South Korea and China.

CANDU reactors are unique in their use of natural-uranium fuel and deuterium oxide, or heavy water, as both moderator to slow down the fission process and coolant within the reactor. The refuelling system is also unique in that CANDU reactors can be refuelled at full power. This is due to the subdivision of the core into hundreds of separate fuel channels each holding a single string of natural uranium fuel bundles, allowing for greater fuel efficiency. In contrast, U.S. reactors, which use enriched uranium fuel, must be shut down during refuelling which may require a planned outage of 15 to 30 days every 18 to 24 months. Both CANDU and U.S. reactors have to shut down from time to time for maintenance and repair. Notwithstanding that CANDU reactors can re refuelled without being shut down, the number of outage days per year for OPG's CANDU reactors currently tends to be greater than the average number of outage days per year for U.S. reactors, primarily due to maintenance and repair work required for pressure tubes and feeders, which are not used in U.S. reactors.

Each CANDU unit is designed with a computerized reactor control system which controls reactor power and the transfer of heat generated in the fuel to the turbines. By changing the demanded power level to the control system, the unit operator can adjust the reactor power level and, therefore, electrical generation, from shut down to full output. The system design also permits on-line maintenance, with redundancy features to improve reliability. Although the normal control process systems are reliable and capable of shutting down the reactor, the stations have also been designed with separate and independent multiple fail-safe safety systems for fast reactor shutdown, emergency cooling and radiation containment. All of OPG's reactors, other than those at the Pickering A station, have two physically separate and independent systems designed to shut down the reactor within two seconds of being activated. Each of these systems is independent of the primary control systems and includes multiple sensors for detecting emergency conditions. The first shutdown system consists of neutron absorbing rods suspended above the reactor, which would fall automatically into the moderator upon detection of an emergency condition. The second shutdown system contains a neutron-absorbing solution, which would be rapidly injected into the heavy water. The Pickering A reactors were originally designed with only one shutdown safety system, which utilized two different shutdown mechanisms. The primary shutdown mechanism consists of fast-acting neutron absorbing rods. An additional slower-acting shutdown mechanism, which drains the reactor moderator to a dump tank, is also present. An enhancement to the original shutdown system, which consists of an independent detection system, is being installed prior to the restart of Pickering A.

OPG's reactors also have an emergency core coolant injection system which would be activated in the event of a pipe break in the reactor coolant system. This system would inject ordinary water into the cooling system to ensure that coolant continues to circulate over the nuclear fuel bundles to prevent them from overheating. In addition, all of OPG's nuclear generating stations have a negative pressure containment system. Each reactor is enclosed in a thick-walled concrete containment building connected to a vacuum building by a large duct. If pressure in the containment building exceeds operating limits, pressure relief valves would automatically open and release any radioactive material into the vacuum building. The negative pressure within the vacuum building, together with steam suppression by a dousing system, would keep radioactive material safely contained within the vacuum building walls. Controlled venting, within permissible levels of release, would also be available for long-term pressure control through filtered-air discharge systems.

Regulatory Affairs

OPG's nuclear operations are heavily regulated. The Canadian Nuclear Safety Commission ("CNSC"), an agency of the Federal Government, regulates the plant operations through its powers under the *Nuclear Safety and Control Act* (Canada). In addition, OPG is also subject to the *Nuclear Liability Act* (Canada), as well as various legislation associated with labour and environmental matters. Under the *Nuclear Safety and Control Act* (Canada), all construction requirements, plant equipment, operating and safety system limits of OPG's nuclear generation stations are subject to approval by the CNSC.

Under licences issued by the CNSC, OPG is required to provide routine reports on operations to the CNSC, which continually monitors and reports on the safety performance of OPG's nuclear generating stations. See "*Business of OPG – Regulation – Nuclear Regulation*".

Reactor Physics

The CNSC requires that OPG and other nuclear operators conduct safety analysis in order to license reactors for operation. One of the objectives of such safety analysis is to demonstrate that an unacceptable release of radioactivity will not occur in the event of a large break loss of coolant accident. In 1999, the CNSC requested OPG to use a new set of computer codes for performing such safety analysis. Analysis performed by OPG with the new codes indicated a reduction in the safety margins from those obtained with the old codes. OPG therefore introduced operational changes that resulted in reductions in a period of operation at reduced reactor power output (referred to as a "derate"). The reduced safety margins identified by the amended reactor physics codes reduced OPG's operating margins and increased OPG's costs.

No OPG reactors are currently derated due to operational limits resulting from large break loss of coolant accident analysis using the new computer codes. The CNSC approved returning all four units at Darlington to operation at 100% of maximum reactor power level in May of 2003 following completion of modifications to increase safety margin and based on their review of safety analysis performed using the new codes. Pickering A and B will continue to be licensed for 100% full power operations with the new analysis. Occasional deratings may, however, be required to respect the new limits imposed by the revised analysis.

Design change may be required to achieve an increase in safety margins sufficient to meet future regulatory requirements. Although a detailed evaluation of the costs associated with such potential design changes have not been completed, it is currently estimated that the cost is likely to fall in a range between \$50 million and \$100 million and will take up to five years to implement.

Nuclear Fuel Procurement

OPG has a varied portfolio of supply contracts for uranium concentrates with suppliers located in uranium-producing regions across the world. The contractual terms have been developed to mitigate price and supply risks. OPG uses one contractor to convert its uranium concentrates into uranium dioxide and has made arrangements with this contractor for an alternate conversion facility in the event the primary conversion facility cannot satisfy OPG's requirements. Price increases for uranium dioxide are limited by contractual terms.

OPG has entered a long-term contract with one independent manufacturer to process uranium dioxide into finished nuclear fuel bundles. Supply security risks are mitigated through provisions contained in the agreement, through the existence of an alternative qualified supplier with some available capacity and through the implementation by OPG of a strategy to increase OPG's inventory of finished fuel bundles such that OPG maintains a 12-month inventory of finished fuel bundles.

OPG believes there is adequate capacity available in each of these segments to accommodate the return to service of the Pickering A units and other Canadian-owned CANDU reactors.

Ancillary Operations

Heavy Water Management

OPG's nuclear generating units contain approximately 7,000 tonnes of radioactive deuterium oxide or heavy water (not including heavy water contained at the leased Bruce stations), which is required to operate OPG's CANDU reactors. OPG also owns an inventory of approximately 1,113 tonnes of heavy water. Such inventory is not stored in the unit; therefore, the inventory of heavy water is non-radioactive. OPG's heavy water was produced at two heavy water plants at the Bruce site between 1973 and 1997. One of these heavy water plants was demolished in 1993-1995; the other ceased operations in 1997. Permanent shut-down was completed by the spring of 1998. Demolition of the second plant and remaining common facilities is expected to be completed in 2006, subject to obtaining regulatory approvals. Follow-up environmental monitoring and site remediation is expected to occur over a period of at least three years after demolition. OPG believes that its inventory of heavy water will be sufficient to replenish supplies as a result of normal operating losses at its nuclear generating stations, including the Pickering A units assuming all four units are restarted, during the expected operating lives of the stations. If the operating lives of these stations are extended, additional supplies of heavy water may have to be purchased from third parties. OPG has in the past sold and intends to continue to sell, surplus heavy water.

Tritium Removal

Tritium is a radioactive substance that is released into the heavy water systems of CANDU reactors as a by-product of the nuclear fission process. OPG operates a facility at its Darlington site that removes tritium from the heavy water used at its nuclear generating stations in order to control the occupational dose exposure to its staff and the release of tritium oxide to the environment. The facility will also be used to detritiate heavy water during the decommissioning of OPG's nuclear generating stations. Some tritium is sold to government-approved organizations for authorized commercial and health industry uses.

Nuclear Waste Management and Decommissioning

As they operate, OPG's nuclear reactors produce used nuclear fuel bundles (high-level radioactive waste); other material that has come in close contact with the reactors but is less radioactive than used fuel, such as ion exchange resins and other structural material and reactor equipment, including pressure tubes (collectively, intermediate-level radioactive waste); and other material used in connection with station operation that is not highly radioactive, such as tools and protective clothing (collectively, low-level radioactive waste). OPG is responsible for the ongoing long-term management of these wastes. In addition, OPG will have to manage radioactive waste associated with decommissioning of its nuclear generating stations after the end of their useful lives. The handling and disposal of radioactive material in Canada is subject to Federal legislation. See "– *Regulation – Nuclear Regulation*".

Federal Government Policy

There is no facility for the permanent disposal of nuclear waste currently in operation in Canada, nor has the CNSC licensed any such facility. Since 1978, Atomic Energy of Canada Limited ("AECL"), under the direction of the Federal Government, and OPG have been researching the concept of disposing of nuclear fuel waste in long-lasting containers that would be placed approximately 1,000 metres underground in stable granite rock ("deep geological disposal").

In July 1996, the Federal Government announced a policy framework to ensure that the disposal of radioactive waste would be carried out in a safe, environmentally sound, comprehensive, cost-effective and integrated manner. A Federal environmental assessment review panel (the "Seaborn Panel") reported to the Federal Government in March 1998 after a 10 year review of the deep geological disposal concept. The Seaborn Panel concluded that the technical safety of the deep geological disposal concept was adequately demonstrated for a conceptual stage of development but that broad public support had not been demonstrated. The Seaborn Panel recommended, among other things, the creation of an independent agency to manage used nuclear fuel, the establishment of a segregated fund (funded by producers and owners of radioactive waste) to finance disposal costs and the study of alternatives to the deep geological disposal concept.

As part of the response to the Seaborn Panel's report, the Federal Government enacted the *Nuclear Fuel Waste Act* (Canada) ("NFWA"), which came into force in November 2002. The NFWA requires the owners of nuclear fuel waste in Canada to establish a waste management organization, incorporated as a separate legal entity, with a mandate to manage and coordinate the full range of activities relating to the long-term management of nuclear fuel waste. In response to the NFWA, in 2002 OPG and other Canadian nuclear waste producers incorporated the Nuclear Waste Management Organization (NWMO)/Société de gestion des déchets nucléaires (sgdn) (the "NWMO") with an Advisory Council of respected Canadian technical and social scientists, academics and others. The NWMO will complete a study of the options available for the long-term management of used fuel by 2005, as required by the NFWA, with Federal Government direction on a long-term plan to follow. The NFWA also required the nuclear fuel waste owners to establish and make payments into trust funds for the purpose of funding the implementation of the long-term management plan. See "- *Provisions for Future Nuclear Related Costs*".

Current Management Practices

Bundles of used nuclear fuel from OPG's reactors and leased reactors at the Bruce site are temporarily stored in water-filled pools known as "wet bays" at the nuclear generating stations, for a "cooling-off" period of at least ten years during which time their radioactivity is substantially reduced. Each nuclear generating station has sufficient capacity to store used nuclear fuel in wet bays corresponding to approximately 15 to 20 years of operation.

After bundles of used nuclear fuel have been stored for their cooling-off period and water-filled pools near their capacity, they are transferred from the wet bays to above-ground concrete canisters ("dry storage") at the corresponding nuclear station site. Currently, used nuclear fuel is in dry storage at the Pickering and Bruce sites. OPG is planning to establish dry storage facilities at the Darlington site by 2007.

OPG's low and intermediate-level radioactive waste is stored at its radioactive waste management facility at the Bruce site, the Western Waste Management Facility. This facility, which continues to be owned and operated by OPG following the decontrol of the Bruce stations, operates under separate licences issued by the CNSC. OPG plans that the low-level and intermediate-level radioactive waste produced by OPG's nuclear facilities and by Bruce Power at the Bruce A and Bruce B stations will continue to be stored at this facility and that its operations will be expanded as necessary.

OPG's current financial planning assumptions for nuclear fuel waste and decommissioning liabilities are that a deep geological disposal facility for used nuclear fuel will be available in 2035 and a low-level radioactive waste disposal facility will be available in 2015. Intermediate level radioactive waste, depending on its radioactive content, will be co-disposed with low-level radioactive waste commencing in 2015 and with used nuclear fuel commencing in 2035. In August 2000, OPG submitted a management plan to the CNSC which revised the reference date for an in-service used fuel disposal facility from 2025, as included in the previous reference plans, to 2035. This plan was confirmed in communications between staff from the CNSC and OPG and forms part of the plans for nuclear waste management and decommissioning liabilities that have been accepted by the CNSC to meet requirements under the *Nuclear Safety and Control Act* (Canada) for a financial guarantee, which was established in July 2003.

OPG has adopted a deferred dismantling strategy for the decommissioning of its nuclear generating stations. Under this strategy, OPG intends to defuel each station immediately after it has ceased operations and prepare the station for storage and monitoring. Thereafter, OPG intends to monitor the station for approximately 30 years, after which it will dismantle the station over a period of approximately ten years. This deferred dismantling strategy has been communicated to the CNSC through preliminary decommissioning plans for all of OPG's nuclear generating stations and operating licences have been issued based on, among other things, its review of this strategy. Financial guarantees required for decommissioning liabilities are also based on this strategy.

Provisions for Future Nuclear-Related Costs

OPG's nuclear facilities commenced production in the early 1970s but until 1982 no accounting or funding provisions were made for liabilities related to the estimated future costs of its nuclear waste management and decommissioning programs. In 1982, Ontario Hydro began collecting provisions through its rates in amounts that, together with interest accumulated on provision balances, were calculated to cover all such future liabilities. These provisions, which were carried in Ontario Hydro's accounts at $2,344 million as at December 31, 1998, were not placed in a segregated fund but were used for general corporate purposes and therefore served to reduce borrowing requirements.

On April 1, 1999, the obligation for nuclear waste management and decommissioning was transferred to OPG. The responsibility for funding these liabilities is described in the Ontario Nuclear Funds Agreement between the Province and OPG. The key provisions of the Ontario Nuclear Funds Agreement are: (i) for OPG to establish two segregated funds, comprising the Used Fuel Segregated Fund (to fund future costs of nuclear used fuel waste management) and the Decommissioning Segregated Fund (to fund the future cost of nuclear fixed asset removal and low and intermediate level waste management); (ii) for the OEFC to be responsible for funding approximately $2,378 million present value as at April 1, 1999 ($1,892 million as at December 31, 2003 after making a cash payment of $1,200 million to the Decommissioning Segregated Fund as of July 24, 2003); (iii) for the Province to limit OPG's financial exposure in relation to the cost of used fuel management; and (iv) for the Province to provide financial guarantees to the CNSC for OPG's nuclear waste management and decommissioning liabilities in return for an annual guarantee fee equal to 0.5% of the amount guaranteed. Although the Ontario Nuclear Funds Agreement is dated April 1, 1999, it did not come into effect until July 24, 2003, when OPG established the Used Fuel Segregated Fund and the Decommissioning Segregated Fund and appointed external investment managers. The Used Fuel Segregated Fund and the Decommissioning Segregated Fund are administered by a third party custodian and are kept separate from OPG's other assets. OPG granted a security interest in both the Used Fuel Segregated Fund and the Decommissioning Segregated Fund to the Province; as a result, these funds are not available to satisfy the claims of OPG's creditors.

The limits to OPG's financial exposure under the Ontario Nuclear Funds Agreement with respect to the cost of long-term storage and disposal of used fuel are as follows (all amounts are present value as at January 1, 1999): (i) OPG will bear all costs up to $4.6 billion; (ii) OPG and the Province will share, on an equal basis, costs incurred between $4.6 billion and $6.6 billion; (iii) OPG will be responsible for 10% of the costs incurred between $6.6 and $10 billion and the Province will be responsible for the remaining 90%; (iv) the Province will be responsible for any costs above $10 billion. As a result, OPG's liability for these used fuel costs will be capped at $5.94 billion assuming 2.23 million bundles of used fuel waste are produced. OPG will, however, be responsible for all incremental costs relating to the management of used fuel bundles in excess of 2.23 million.

Under the Ontario Nuclear Funds Agreement, the Province guarantees the rate of return earned in the Used Fuel Segregated Fund at a specified rate of 3.25% over the change in the Ontario consumer price index. Therefore, the Province is obligated to make additional contributions to the Used Fuel Segregated Fund if this fund earns a rate of return that is less than the rate of return guaranteed by the Province. If the return on the assets in the Used Fuel Segregated Fund exceeds the Province's guaranteed rate, the Province is entitled to the excess.

Under the Ontario Nuclear Funds Agreement, OPG's required contributions to the Used Fuel Segregated Fund and the Decommissioning Segregated Fund are determined based on internally prepared reference plans, which are prepared with the assistance of external consultants and are based on external practices and benchmarks. Under the reference plan, OPG has estimated the total present value of its future nuclear waste management and decommissioning costs (including its responsibilities in connection with the Bruce stations) based on cost estimates and assumptions as to the remaining useful lives of the nuclear plants and proposed methods of nuclear waste disposal. Cost estimates reflect management's views supplemented by external advice as well as international benchmarks. OPG's estimates for incurred liability as of December 31, 2003 are set out in the following table:

Present Value of Nuclear Waste Management
and Nuclear Decommissioning Cost Estimates for Incurred Liability to Year End 2003

	Present Value December 31, 2003 (millions of dollars)
Incurred liability[1]:	
Liability for nuclear used fuel management	$4,451
Liability for nuclear decommissioning and low and intermediate level waste management..	3,289
Liability as at December 31, 2003	7,740
Less: Decommissioning Fund[2]	3,641
Less: Used Fuel Fund[2]...	1,587
	$5,228
Net unfunded liability...	$ 2,512

Notes:

(1) Based on OPG reference plans for nuclear waste management and decommissioning.
(2) Includes The Ontario NFWA Trust balance of $648 million.

The current cost estimate for nuclear waste management and decommissioning incorporates several significant assumption changes which lower the overall liability when compared to the baseline liability in the Ontario Nuclear Funds Agreement. These changes include a reduction due to a delay in the in-service date for used fuel disposal facilities from 2025 to 2035, a reduction due to the recognition of certain costs associated with dry storage of used nuclear fuel during station operating life, a reduction due to the recognition of additional costs related to nuclear waste management programs, and an increase due to low and intermediate level nuclear waste management programs.

The NFWA requires nuclear fuel waste owners to establish a trust fund to finance implementation of recommendations on long-term used fuel management. OPG made an initial deposit of $500 million into a trust fund in November 2002 as required under the NFWA and an additional $100 million in 2003. OPG will deposit an additional $100 million annually until the Federal Government has approved a long-term plan, which is not expected before 2006. For purposes of the Ontario Nuclear Funds Agreement, the Ontario NFWA Trust forms part of the Used Fuel Segregated Fund. The NFWA requires the NWMO to submit, by November 2005, a study setting out the proposed approaches to managing nuclear fuel waste (including deep geological disposal in the Canadian Shield, storage at nuclear reactor sites and centralized storage either above or below ground) as well as its recommendation as to which of the proposed approaches should be adopted. The study must include for each approach a technical description; a comparison of benefits, risks and costs of that approach compared with those of the other approaches; an implementation plan; and the formula to calculate the annual amount required to finance the approach. The study is to be submitted to the Federal Minister of Natural Resources who is to make a recommendation to the Governor in Council. One of the approaches for the management of nuclear fuel waste shall be selected by the Governor in Council from among those set out in the study. Implementation requirements after selection of an approach are included in the NFWA.

Upon the Ontario Nuclear Funds Agreement coming into effect in July 2003, OPG made initial contributions of $534 million to the Decommissioning Segregated Fund and $1,335 million to the Used Fuel Segregated Fund. The initial contribution to the Decommissioning Segregated Fund is sufficient, when combined with the OEFC contribution and based on current approved estimates, to fully fund OPG’s obligations in respect of decommissioning liabilities. A rate of return target of 5.75% per annum was established for the Decommissioning Segregated Fund. Under the Ontario Nuclear Funds Agreement, if there is a surplus in the Decommissioning Segregated Fund beyond a minimum over-funding ratio, OPG may direct 50% of the surpluses to the Used Fuel Segregated Fund and the OEFC is entitled to the remaining 50% of such surplus. OPG bears the risk and liability for cost estimate increases and fund earnings in the Decommissioning Segregated Fund.

The Used Fuel Segregated Fund is funded in accordance with the Ontario Nuclear Funds Agreement, using the reference plans and associated cost estimates, which have been deemed approved by the Province and may be adjusted from time to time in accordance with the Ontario Nuclear Funds Agreement. In addition to the initial contribution of $1,335 million to the Used Fuel Segregated Fund, OPG is required under the Ontario Nuclear Funds Agreement to contribute approximately $454 million per annum to the Used Fuel Segregated Fund during the period from 2003 to 2008. OPG's maximum contribution to the Used Fuel Segregated Fund would be approximately $700 million annually for the period from 2003 to 2008, if OPG’s liability estimate reached the maximum amount possible under the liability thresholds.

OPG's contributions to the Used Fuel Segregated Fund or to the Decommissioning Segregated Fund and any consideration payable in the year to acquire all or part of an interest in such funds are deductible under the proxy tax regime. In addition, investment income earned on these funds is treated by OPG as being exempt from both proxy tax and tax payable under both the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario). If the investment income earned on these funds becomes taxable, OPG will bear the entire additional cost of the tax and its required contributions to the funds would be increased accordingly. See “*Business of OPG – Relationship with the Province and Others – Stranded Debt and Proxy Taxes”, “Taxation of Provisions for Future Nuclear-Related Costs”* and see “*Business of OPG – Risk Factors – Nuclear Operations*”.

Changes to the estimated level of contribution to the funds will depend on any changes to the reference plans and associated cost estimates and tax treatment. OPG's required contributions could increase, for example, if cost estimates increased, the operating life of the nuclear stations decreased, if the funds became subject to tax or if the NWMO is unable to receive the same sales tax treatment that OPG would be entitled to receive if the NWMO had not been established – see "*Business of OPG – Relationship with the Province and Others – Taxation of Provisions for Future Nuclear – Related Costs*". OPG's contributions to the Used Fuel Segregated Fund may not, however, decrease until the estimated liabilities are 60% funded and, after that point, only on a partial basis until the fund is 90% funded. Under the Ontario Nuclear Funds Agreement, payments to the funds are recalculated each time there is a new reference plan and in certain other events. Any new reference plan must be approved by the Province. Reference plans are required to be prepared at least every five years and more frequently if required by the CNSC or if there is a greater than 5% change in the relevant cost estimate.

The CNSC requires obligations for nuclear waste and decommissioning to be subject to financial guarantees. The CNSC published its Regulatory Guide G-206 on "*Financial Guarantees for the Decommissioning of Licensed Activities*" in June 2000. This Regulatory Guide sets out the requirements for the establishment and maintenance of measures to fund the decommissioning of licensed facilities, including the management of all wastes associated with the licensed activity. This Regulatory Guide permits financial guarantees to be in the form of a government guarantee. Under the Ontario Nuclear Funds Agreement the Province would, if required, provide this guarantee in relation to OPG's obligations for an annual fee of 0.5% of the guarantee given. An application was made in November 2002 to the CNSC for the amendment of OPG Class 1 licences to include conditions for financial guarantees. A hearing with the CNSC was held in April 2003 and the financial guarantee was in place in July 2003. The guarantee bridges the difference between the CNSC value of the associated liabilities and the value of the assets.

In the case of the Bruce A and Bruce B stations leased to Bruce Power, OPG continues to assume long-term responsibility for the used fuel and low and intermediate level radioactive waste generated by Bruce Power, as well as responsibility for eventual decommissioning. See *" – Generation Operations – Nuclear Operations – Bruce Lease"*.

Bruce Lease

Effective May 11, 2001, OPG leased its Bruce A and Bruce B nuclear generating stations and sold certain related assets to Bruce Power L.P. ("Bruce Power"). The lease payments OPG receives consist of a monthly fixed payment and a supplemental payment that varies, based on the number of generating units operated by Bruce Power over the payment period. In 2003, the combined fixed and supplemental lease payments received was approximately $178 million. A $225 million note receivable, which was part of the initial payments for the transaction, was paid to OPG in 2003. In February 2003, the majority ownership of Bruce Power was transferred from British Energy to a consortium comprised of TransCanada PipeLines Limited, BPC Generation Infrastructure Trust, the Ontario Municipal Employees Retirement Board and Cameco Corporation. The Power Workers Union and The Society of Energy Professionals continue to hold a minority equity stake. The operating lease has an initial term of approximately 18 years and includes options to extend the lease for up to another 25 years. Certain amendments were made to the lease as part of the February 2003 transfer from British Energy to the consortium including Base Rent payable monthly, as opposed to semi-annually, a minimum annual rent of $190 million and a 2 year extension to January 2008, of the date after which Bruce Power may terminate the lease under certain circumstances, on the payment to OPG of $175 million.

OPG continues to assume long-term responsibility for the used fuel and low and intermediate level radioactive waste generated by Bruce Power, as well as responsibility for eventual decommissioning, following certain preparatory work which is the responsibility of Bruce Power. Fees in respect of used fuel and decommissioning are embedded in the lease payments while ongoing fees are payable for low and intermediate level waste, based on volume of this waste received by OPG from Bruce Power. Radioactive waste materials will be turned over to OPG during the term of the lease in accordance with nuclear waste agreements between the parties. Under the lease agreement OPG retains the obligation to provide the financial guarantees for the decommissioning of licensed facilities that the CNSC requires regarding the discharge of these liabilities. See "*– Risk Factors – Regulatory Risks - Market Power Mitigation/Decontrol*".

Human Resources

As of December 31, 2003, OPG had approximately 11,000 full-time employees and approximately 2,100 contract, casual, construction and non-regular staff. The majority of OPG's full-time employees are represented by two unions; approximately 6,800 by the Power Workers' Union (the "PWU") and approximately 3,000 by The Society of Energy Professionals (the "Society"). OPG directly/or indirectly hires casual construction staff from 20 different unions, 17 of which are international building trades unions that negotiate with the Electrical Power System Construction Association ("EPSCA"). OPG is a member of EPSCA and is therefore subject to the union contracts that EPSCA enters into on behalf of its members. In addition, OPG negotiates directly with and hires three additional Building Trade Unions. There are approximately 1,150 executive and managerial staff that are not represented by a union.

In January 2002, OPG announced a restructuring plan involving staff reductions, relocation and re-organization, the purpose of which was to better align OPG resources and improve efficiency and effectiveness. As at December 31, 2003, 1090 staff had left the organization through voluntary severance packages (excluding staff reductions due to long term disability or other reasons) with a further 220 still planned to leave. In a related initiative, OPG will be relocating nuclear related head office personnel to Durham Region where OPG's two nuclear generating stations are located. Similarly, head office personnel that support OPG's hydroelectric and fossil stations were relocated to either the Sir Adam Beck facilities near Niagara Falls or to the Nanticoke Generating Station, located in Haldimand County. Restructuring charges of approximately $290 million have been recorded by OPG as of December 31, 2003 with respect to this restructuring plan.

There have been and continue to be challenges in managing OPG's large work force involving multiple unions. However, OPG believes that its working relationship with its represented employees has steadily improved over the past five years, consistent with an acknowledgement of the necessity of working co-operatively in the new business environment. In September 2001, the PWU and OPG negotiated a four year agreement to provide labour stability as changes in the electricity industry took place. This was the first time an agreement was reached so far in advance of the expiry of an existing agreement and the first time since 1996 that an agreement was reached without the assistance of a third party arbitrator/conciliator. The contract also contained significant changes to influence productivity through skill broadening and contract simplification.

The Society Collective Agreement was renewed through mediation/arbitration in March 2004 for a one year period, and will expire on December 31, 2004. OPG and the Society have had a longstanding provision in the Society's collective agreement that provides for third party arbitration rather than strike/lockout in the event the parties are unable to reach agreement during collective agreement renewal negotiations. The Society has never engaged in a work stoppage.

In 1999, the Society, the PWU and OPG established a "Partnership Agreement" setting out a series of principles that guide the parties in managing day-to-day labour and employment matters. These principles established the framework for the most recent round of collective agreement negotiations with both unions.

OPG also negotiates directly with three building trade unions in the construction sector, the Machinists, the Brick and Allied Craft Union ("BACU") and the Canadian Union of Skilled Workers ("CUSW"). Collective Agreements for each of these unions expire April 30, 2004. OPG anticipates that negotiations with the Machinists and BACU will commence shortly. CUSW is presently before the Ontario Labour relations Board seeking to expand its bargaining rights to include electrical work done by contractors for OPG, as distinct from electrical work done by direct hires, over which CUSW already has rights. It is likely that OPG will commence direct bargaining with the CUSW when this issue is resolved.

OPG also provides programs that help prepare OPG for competition in the Ontario market, including programs that attract and retain skilled personnel, enhance the business and financial orientation of employees, ensure that OPG has appropriate succession planning and leadership development and support increased focus on safety and wellness. See "– *Health and Safety – Occupational Health and Safety*".

Health and Safety

Occupational Health and Safety

OPG is committed to achieving excellent safety performance, striving for continuous improvement and the ultimate goal of zero injuries. Safety performance is measured using two primary indicators, the Accident Severity

Rate ("ASR") and the All Injury Rate ("AIR"). In 2003, the ASR and AIR performance were better than target, and were the best performance that OPG has achieved since its incorporation in 1999.

Improvements have been made as a result of a strong safety management system, targeted risk mitigation programs, and a commitment and focus on safety. One of the key strategies used to achieve this improvement has been the development and implementation of formal safety management systems based on the British Standard Institute's Occupational Health and Safety Assessment Series 18001 ("OHSAS 18001"). These systems exist at both the corporate and site levels, and serve to focus OPG on proactively managing safety risks and developing targeted risk mitigation programs. In addition, significant improvements were made to OPG's Corporate Safety Rules and the Work Protection Code, to further raise the bar on managing safety risks.

OPG's safety strategy has included the development of a strong safety culture, where employees are encouraged to use conservative decision making and a questioning attitude. Safety communications, using a variety of media, have also contributed to this culture using clear, consistent messages about safety expectations, hazard awareness, and lessons learned from safety incidents. The safety culture has been further strengthened through partnerships with our unions, who share a mutual goal for an injury-free workplace.

Oversight and reporting by corporate and site safety functions provided senior management with regular information on the effectiveness of the safety management efforts, compliance to legal and corporate requirements, and safety performance trends. Oversight activities included internal and external safety management system audits, Work Protection Code audits, and safety risk reviews on specific operational risks (i.e., public waterways safety, coal handling systems, and plant configuration management). OPG also has a rigorous incident management system, which requires that all incidents, including near misses, be reported and investigated, and that corrective action plans are developed to ensure that reoccurrences are prevented.

Notwithstanding OPG's commitment to safety, OPG's Nanticoke coal-fired generating station suffered an employee fatality in October 2002. See *"-Generation Operations-Fossil Operations-Occupational Safety"*.

Public safety and contractor safety are key components of the safety improvement strategy, and are re-enforced in OPG's Health and Safety Policy. OPG expects its contractors to maintain an equivalent level of safety to that of our employees, and to strive for zero injuries in our workplaces. OPG has committed to improve contractor management by developing a "best in class" contractor management system. Development of this system is nearing completion, with implementation planned for 2004. Priorities in 2003 included focus on public safety improvements at the hydroelectric sites.

Younger worker safety was a new priority in 2003, as OPG prepares for employee retirements and the resulting introduction of many new and younger workers over the next 3 to 5 years.

Radiation Safety

OPG manages a radiation protection program designed to minimize detrimental health effects to employees and members of the public. OPG follows developments in the field of radiation protection as documented by the International Commission on Radiological Protection (the "ICRP"), the United Nations Scientific Committee on the Effects of Atomic Radiation and the U.S. National Council on Radiation Protection and Measurements. The ICRP is widely recognized as the main source of expert advice regarding protection from the harmful effects of ionizing radiation. This agency periodically issues recommendations concerning principles of radiation protection. The recommendations of the ICRP are usually adopted without significant change by most countries and are incorporated into their laws. In Canada, the CNSC is the Federal agency that regulates radiation protection. The Canadian Radiation Protection Regulations are based on the recommendations of the ICRP, and OPG nuclear facilities conform to these regulations.

Radiation exposures to plant personnel and the public are limited by station design and by adherence to approved operating procedures. Over the years, OPG has been a leader in the application of the principles of keeping radiation doses as low as reasonably achievable. The CANDU station design has steadily improved with each new plant. Notable achievements were the reduction of radiological source terms (such as Cobalt-60), the implementation of a tritium displacement and removal strategy and the integration of enhanced shielding in the design of plants. OPG's administrative limits for occupational exposure are set below regulatory limits to ensure that regulatory limits are not exceeded. Operating targets for radiological emissions are even more restrictive and are typically small fractions of the regulatory limits.

Each nuclear site has a radiation protection department which continually reviews and assesses the radiation control program. The department's staff complement includes "Responsible Health Physicists" who have been certified by the CNSC. These Responsible Health Physicists are charged with monitoring compliance with radiation protection policies and regulations.

All persons who enter the operating area of a nuclear facility are assigned a radiation protection qualification that determines access and working rights. Workers that perform radioactive work are extensively trained to look after their own radiation protection or work under the guidance of a radiation protection coordinator. Radioactive work is done in accordance with approved work plans or procedures.

A dosimetry program licensed by the CNSC monitors radiation exposures of workers. Results of the dosimetry program are routinely reported to the National Dose Registry of Health Canada, as required by the CNSC. Potential radiation exposure of the public is monitored through a comprehensive environmental program that has been designed to monitor site specific exposure pathways to a member of the public, such as drinking water. The results of this monitoring program are reported annually to the CNSC.

As a condition of receiving operating licences for its nuclear facilities, OPG has developed comprehensive emergency plans which detail its planned response to reactor accidents as well as accidents involving the transportation of radioactive materials. These plans dictate how OPG will work with municipal, regional, provincial and Federal agencies to safeguard station personnel and members of the public in the unlikely event of a radiation emergency at one of OPG's facilities. Plant staff regularly participate in emergency exercises to maintain their skills and to continuously improve response capability for such events.

Public Safety

A commitment to Public Safety is an important part in the operation of OPG generating stations and is highlighted in OPG's Health and Safety Policy.

In 2003, a waterways public safety technical audit was conducted. This audit focused on the status of public safety management plans for all hydroelectric stations to determine compliance with the Guidelines for Waterways Public Safety and related governing documents. The audit determined that all plant groups were on track to complete their approved action plans. Control measures implemented included revision of operational procedures, installation of 34 audible alert systems, over 2488 new warning signs, 17,500 metres of fencing, 14,300 metres of floating safety booms and targeted security patrols. In total, $16.3M was spent on these installations in 2002 and 2003. Significant public awareness and outreach campaigns were carried out in 2003 in all communities where OPG operates hydroelectric facilities, and forms a key part of the public safety program. This outreach continues in 2004 through various media outlets. It is anticipated that ongoing interaction with the Ministry of Natural Resources and the Canadian Dam Association will facilitate the development of a new Public Waterways Safety regulations for dam owners in late 2004.

Notwithstanding OPG's commitment to public safety, in June 2002, two fatalities to members of the public occurred at OPG's Barrett Chute hydroelectric facility. The OPP are investigating whether to lay criminal charges in relation to this event.

Intellectual Property

In connection with the reorganization of Ontario Hydro, Ontario Hydro's patents and certain other transferable intellectual property assets, including trade-marks, copyrights and industrial design and technical information (including know-how and technical knowledge) were transferred to certain successor corporations, including OPG. Certain of the intellectual property assets of OPG have, in turn, been licensed by OPG to Hydro One, the Electrical Safety Authority, and other entities. Licences of intellectual property assets among OPG, Hydro One and the Electrical Safety Authority are generally non-exclusive, royalty free and perpetual and cannot be terminated without the written consent of the other party.

Research and Development and Venture Capital

The majority of OPG’s research and development effort is operationally based and primarily focused on short-term, lower-risk programs aimed to improve productivity, reduce costs, meet changing environmental and regulatory considerations and make other types of incremental improvements that will improve operational performance and operating results. OPG has adopted this approach by decentralizing these operational research and development initiatives to operating business units.

Most of OPG's nuclear research and development is conducted at Atomic Energy of Canada Limited and at private sector facilities and focuses on improving plant performance, plant life cycle management and regulatory excellence.

Longer term strategic programs are managed at the corporate level. Corporate programs focus on the advancement and commercialization of next generation technologies in support of OPG's business activities and include technologies such as fuel cells, distributed generation and energy storage.

OPG Ventures Inc., a wholly owned subsidiary of OPG, was incorporated in March 2001 for the purpose of investing in emerging technologies related to the energy industry. OPG Ventures Inc. had invested $42 million as of December 31, 2003 and had $14 million in outstanding commitments. Included in the initial investments are companies developing technologies such as fibre optic high voltage power measurement, energy generation from waste using plasma gasification and enterprise energy management solutions.

OPG is considering whether further investments in research and development are necessary or appropriate.

Information Technology

OPG’s competitiveness depends in part on its information technology systems and operations. OPG has implemented, and is supporting the information technology systems necessary to manage the changes in Ontario’s electricity market. These systems automate and integrate business processes to facilitate OPG’s participation in the IMO-administered market and other interconnected markets and include systems for production planning, spot market bidding, generation dispatch, settlement of spot market and bilateral transactions, billing, customer information and services, trading and risk management.

OPG has also implemented a number of strategies to enhance the management of the information systems support for its business units. These include: enhanced information technology expertise through training and hiring, continued reductions in the cost of information technology services and the successful delivery of large scale projects, such as the fossil and hydroelectric systems' restructuring and rebuilding of the data centre and communications networks. In November 2000, OPG entered into a joint venture agreement with Business Transformation Services Inc., a wholly-owned subsidiary of Cap Gemini Ernst & Young Canada Inc., to transfer the operation and support of the bulk of OPG’s information services to New Horizon System Solutions Inc. (“New Horizon”). Approximately 520 employees from OPG’s Information Services Group transferred to New Horizon on February 1, 2001. Effective March 28, 2002, OPG sold its remaining 49% interest in New Horizon to Business Transformation Services Inc. Effective July 25, 2003, OPG entered into another agreement with Business Transformation Services Inc. to transfer the operation and support of information services associated with OPG’s Energy Markets business to New Horizon. New Horizon will continue to perform infrastructure management, application development, application support and maintenance, network management, data centre operations and help desk support services for OPG on a contract basis and will also deliver information technology services throughout the energy industry. The New Horizon divestiture has allowed OPG to reduce the costs associated with managing and maintaining information systems internally, while allowing management to focus on strategic and core business priorities.

In January 2001, OPG entered into the EBT Express joint venture with Toronto Hydro Corporation. Effective March 7, 2002, EBT Express, Screaming Power Inc. and Screaming Solutions Ventures Inc. (which, among other things, is in the business of developing, marketing and licensing secure messaging software products and systems for use in the electricity industry) combined their operations into a new company, “The SPi Group”. The SPi Group's electronic clearinghouse technology is now in production and provides e-commerce services for retail transaction management to market participants in the energy sector including utilities, retailers and other energy services providers.

Insurance

The principal types of discretionary insurance carried by OPG include commercial general liability, all-risks property, boiler and machinery breakdown, including statutory boiler and pressure vessel inspections and business interruption. In addition to covering OPG's non-nuclear facilities, this insurance applies to the conventional operations at OPG's nuclear generating stations. OPG also maintains property insurance for damage to the nuclear portions of its generating stations which complements the conventional property insurance program. As a result of significant changes in the insurance marketplace over the past couple of years, the available coverage and limits may be less than the amount of insurance obtained in the past and the recovery for losses due to terrorist acts may be limited.

OPG purchases insurance coverage as required by statute, namely owned and leased automobile and nuclear liability. OPG believes and has been advised by insurance professionals that the coverages, amounts and terms of its insurance agreements are consistent with prudent Canadian industry practice.

As required by the *Nuclear Liability Act* (Canada) (the "NLA"), OPG maintains $75 million per incident of nuclear liability insurance for each of its nuclear generating stations (Pickering A and B are considered to be one station), for which there is no deductible amount. The NLA is currently under review, which will likely result in a requirement for increased insurance coverage. See *"– Regulation – Nuclear Regulation"*.

Relationship with the Province and Others

Provincial Authority

As a corporation created under and governed by the *Business Corporations Act* (Ontario), the Corporation's management is supervised by its Board of Directors which is obligated by law to act in the best interests of the Corporation. The Province owns all of the Corporation's issued and outstanding common shares and thereby has the power to determine the composition of the Corporation's Board of Directors. Following management changes that occurred in December of 2003, which involved the departure of the Chairman, Chief Executive Officer, Chief Operating Officer and the Board of Directors, the Province entered into a Unanimous Shareholder Agreement which restricted the powers of the newly appointed Board of Directors in favour of the Province.

The OEB, the principal regulator of Ontario's electricity industry, is an independent quasi-judicial tribunal created by the *Ontario Energy Board Act, 1998* (the "OEB Act, 1998"), reporting to the Ontario legislature through the Minister of Energy. The OEB is obligated to implement policy directives approved by the Lieutenant Governor in Council. See *"– Regulation – Ontario's Electricity Industry – Legislation"*.

On June 26, 2003, the *Ontario Energy Board Consumer Protection and Governance Act, 2003* received Royal Assent. This legislation was aimed at improving the efficiency, accountability and governance of the OEB, and to increase the OEB's level of accountability to the Province. The Minister of Energy and the Chair, on behalf of the OEB, are required to enter into a Memorandum of Understanding every three years. The legislation also made significant changes to the governance of the OEB, setting the number of Board members at a minimum of five. A chair and two Vice-chairs are also to be appointed. The Chair and Vice-chairs form a Management Committee, responsible for managing the activities of the OEB. The *Ontario Energy Board Consumer Protection and Governance Act, 2003*, also provides for an Advisory Committee, independent of the OEB, which performs duties and provides advice to the Management Committee as specified by either the Minister or the Management Committee. The Minister will appoint members to the Advisory Committee.

The IMO is a separate entity operating independently through its board of directors. The Province exercises statutory powers in relation to the IMO. The IMO's board of directors is responsible for managing or supervising the management of the IMO's business and affairs and board members are subject to fiduciary obligations in the performance of their duties in accordance with the *Electricity Act, 1998* (Ontario). Directors of the IMO are appointed by the Province for terms not exceeding three years and may be reappointed, but may only be removed by the Province or the board of directors of the IMO for cause. The Chief Executive Officer of the IMO is selected by the board and also serves as an IMO director. See *"– Regulation – Ontario's Electricity Industry – The IMO"*.

Transfer Orders and OEFC Indemnity

On April 1, 1999, pursuant to transfer orders made by Order-in-Council pursuant to the *Electricity Act 1998* (Ontario), OPG purchased and assumed all of the interest of Ontario Hydro in all officers, employees, assets, liabilities, rights and obligations of Ontario Hydro directly or indirectly used in or relating in any manner to the activities carried on by Ontario Hydro as a generator as at April 1, 1999. OPG entered into an indemnity agreement with the OEFC in respect of assets, liabilities, rights and obligations pertaining to OPG's business. Under this agreement, the OEFC has indemnified OPG in respect of: the failure of the transfer orders to transfer any asset, right or thing, or any interest related to OPG's business; any adverse claims or interests, excluding certain claims and rights of the Crown, or any deficiency or lack of title in respect of any asset, right or thing or any interest, which was intended to be transferred. The indemnity specifically excludes various claims, including: (i) any matter in respect of which OPG has agreed or is required to indemnify the OEFC pursuant to or in connection with any transfer order; and (ii) any claims related to First Nations title or rights, or the absence of permits, rights-of-way, easements or similar rights in respect of lands held for First Nations bands or bodies under the *Indian Act* (Canada).

The indemnity does not cover the first $10,000 in value of each claim and only applies to the amount by which the total of all claims exceeds $20 million. OPG is obliged to pay the OEFC a fee for the indemnity of $5 million per year, until such time as OPG and the OEFC agree that the indemnity should be terminated. The Province has guaranteed the obligations of the OEFC under the indemnity agreement.

Relationship with the Province

Shareholder Agreement and Dividend Policy

The Corporation and the Province have entered into a shareholder's agreement relating to certain aspects of the governance of OPG. The shareholder's agreement addresses such issues as the provision, from OPG to the Province, of the information necessary to allow the Province to periodically inform Ontario's legislature regarding matters such as the ongoing performance of OPG, progress reports concerning compliance with market power mitigation, information in respect of matters requiring shareholder approval and appropriate financial reports. In addition, the shareholder's agreement addresses OPG's governance relationship with the Province with respect to certain actions, including any proposal to issue or transfer shares in the Corporation or any of its subsidiaries, the preparation of long-term business plans, matters concerning dividend policy and the entering into of any major transaction by the Corporation or any of its subsidiaries which would potentially have a material effect on the financial interest of the Province or OPG's ability to make payments in lieu of taxes. The shareholder's agreement also precludes the release by the Province of non-public, commercially sensitive information regarding OPG to Hydro One or others.

The declaration and payment of dividends are at the sole discretion of the Corporation's Board of Directors and will be dependent upon the Corporation's results of operations, financial condition, cash requirements, securities legislation and other factors considered relevant by the Corporation's Board of Directors. The Corporation's policy is to declare and pay regular dividends on its common shares held by the Province equal to approximately 35% of its net income from time to time. In addition, the Corporation may from time to time declare special dividends on account of any portion of the proceeds of any decontrol transactions.

The Corporation made dividend payments to the Province in the aggregate amount of $16.55 million on March 31, 2003, representing dividends remaining to be paid on account of 2002 results.

As noted, in December 2003 the Province announced it had accepted the resignations of OPG's Chairman, President and Chief Executive Officer, and Chief Operating Officer, as well as the resignations of all other members of the Board of Directors. The Province appointed an acting President and CEO, Richard Dicerni, who previously served as Executive Vice President and Corporate Secretary of OPG. In December 2003, a new Board of Directors for OPG was appointed for an interim period, with the Honourable Jake Epp named Chairman of the Board. On April 15, 2004, the Minister of Energy announced that the Honourable Jake Epp has been confirmed as OPG's

Chairman of the Board effective immediately, and that a search would immediately commence for nine new members of OPG's Board of Directors, as well as a new Chief Executive Officer.

The Board of Directors currently act as the Audit Committee. As of December 2003, the other committees of the Board of Directors have been suspended for an interim period. However, the Board of Directors as a whole fulfils the obligations of the other committees.

In December 2003, the Province also passed a declaration restricting the powers of the Board of Directors with respect to certain personnel matters and expenditures related to Pickering A Units 1, 2 and 3. OPG also continues to be subject to the shareholder's agreement referred to above.

Ontario Nuclear Funds Agreement

OPG and the Province have executed the Ontario Nuclear Funds Agreement, under which the Province has agreed to limit OPG's financial exposure in relation to certain used fuel management costs. See "*– Generation Operations – Nuclear Operations – Nuclear Waste Management and Decommissioning – Provisions for Future Nuclear-Related Costs*".

Provincial Guarantee

The Province has provided a guarantee in favour of the Corporation and has guaranteed certain obligations of the OEFC to OPG under the indemnity agreement between OPG and the OEFC.

Stranded Debt and Proxy Taxes

Stranded Debt

One of the OEFC's purposes under the *Electricity Act, 1998* (Ontario) (the "Electricity Act'), is to manage its outstanding liabilities, including "stranded debt". The Electricity Act defines stranded debt as the amount of the debt and other liabilities of the OEFC that, in the opinion of the Minister of Finance, cannot reasonably be serviced and retired in a competitive electricity market. At April 1, 1999, the Province estimated the stranded debt to be $20,900 million, representing the difference between OEFC's existing debt and liabilities of approximately $38,100 million and the aggregate enterprise value of OPG, Hydro One and the IMO of $17,200 million. Although OPG has no obligations in connection with the stranded debt, the Electricity Act does provide for stranded debt to be paid over time by payments to the OEFC by participants in the electricity sector, including OPG, Hydro One and the local distribution companies. These payments include proxy taxes, debt retirement charges levied on electricity consumers, and other amounts that may be payable by local distribution companies or municipal corporations on the transfer of their electricity business.

Proxy Taxes

The Corporation and its Canadian subsidiaries are exempt from tax under the *Income Tax Act* (Canada) and *Corporations Tax Act* (Ontario) because the Province is the sole shareholder of the Corporation, the Corporation owns not less than 90% of the shares or capital of its subsidiaries and no non-government entity has an option or other right to acquire more than 10% of such shares. The Electricity Act, however, requires each corporation to pay to the OEFC for each taxation year, an amount referred to as "proxy tax" as long as it continues to be exempt from tax under the *Income Tax Act* (Canada) and *Corporations Tax Act* (Ontario). Proxy taxes in general, equal the amount of tax payable under the rules in the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario), as modified by the regulations to the Electricity Act, if the Corporation were not exempt. Under the regulations to the Electricity Act, contributions to a nuclear decommissioning fund or nuclear used fuel fund are deductible in computing income subject to proxy tax. In addition, any related investment income earned on these funds is treated by the Corporation as being exempt from proxy tax and tax under the *Income Tax Act* (Canada) and under the *Corporations Tax Act* (Ontario). See *"– Relationship with the Province and Others – Stranded Debt and Proxy Taxes",* and *"Relationship with the Province and Others -Taxation of Provisions for Future Nuclear-Related Costs",* and *"– Generation Operations – Nuclear Operations – Nuclear Waste Management and Decommissioning – Provisions for Future Nuclear-Related Costs".*

The Electricity Act also provides that the Corporation and certain of its Canadian subsidiaries are required to make payments in lieu of property tax to the OEFC on their non-hydroelectric generating station buildings and structures each year. These payments generally equal the difference between property taxes otherwise payable if these assets were privately-owned, and the amount payable to municipalities as determined under the Electricity Act. This difference is paid to the OEFC to be applied to its stranded debt. One of the purposes of the proxy tax and the payments in lieu of property tax is to create a level playing field, from a tax perspective, between OPG and other generators seeking to sell electricity in the Ontario market. The Corporation's hydroelectric generation operations do not make payments in lieu of property taxes because they are subject to the gross revenue charge regime. See *"– Relationship with the Province and Others – Special Charges on Hydroelectric Generating Stations"*.

Special Charges on Hydroelectric Generating Stations

Since 2001, the Corporation has been paying gross revenue charges based on the gross revenue derived from the annual generation of electricity from its hydroelectric generating stations. These charges are calculated on a station-by-station basis and consist of a graduated portion, paid to the Ministry of Finance and the OEFC to fund the stranded debt; and an additional 9.5% portion, paid to the Province because it replaces the water rental payments under the old system. See *"– Generation Operations – Hydroelectric Operations – Water Payments"*. The graduated portion consists of four tiers of payments as follows- the gross revenue arising from the first 50 gigawatt hours of annual generation from the generating station is assessed at 2.5%, the next 350 gigawatt hours is assessed at 4.5%; the next 300 gigawatt hours is assessed at 6%, and the generation above 700 gigawatt hours is assessed at 26.5%. The additional gross revenue charge of 9.5% is levied on the gross revenue of the Corporation's hydroelectric generating stations that are located on provincial Crown lands.

Pursuant to the regulations of the Electricity Act, the gross revenue of a station for the period January 1, 2001 to December 31, 2003, is determined by multiplying the station's annual generation for the year by a price of $40 per MWh. The determination of gross revenue post-2003 will be set by future regulations which have not yet been released. The Corporation's gross revenue charges for 2003 were $310 million. Property tax on land and buildings not used in connection with the hydroelectric generating station will continue to apply and be paid by the Corporation directly to the municipality and is not expected to be significant.

Taxation of Provisions for Future Nuclear-Related Costs

The Corporation treats any related investment income earned by the nuclear decommissioning and nuclear used fuel funds as being exempt from proxy tax – see "*– Stranded Debt and Proxy Taxes"*. Such income is also tax-exempt under the *Income Tax Act* (Canada) and *Corporations Tax Act* (Ontario) because the Corporation is tax-exempt. However, because the Corporation established a trust pursuant to the *Nuclear Fuel Waste Act* (Canada) to fund part of its long-term management of used fuel, this trust is taxable as a separate entity under the *Income Tax Act* (Canada). As a taxable entity, the trust would normally be required to pay tax on any related investment income earned because such funds remain in the trust. However, the Federal Government has indicated to the provinces of Ontario, Quebec and New Brunswick, that it will take appropriate measures to ensure that such income is exempt from taxation under the *Income Tax Act* (Canada) if the beneficiaries of the trust are the Province, the Federal Government, or a Crown-owned nuclear energy corporation that is exempt from taxation under the *Income Tax Act* (Canada). Since the trust fund meets these conditions, its income would be tax-exempt under the *Income Tax Act* (Canada).

The Corporation is currently entitled to recover its goods and services tax ("GST") under the *Excise Tax Act,* (Canada) paid on its purchases and expenses related to its nuclear waste operations. Under the *Nuclear Fuel Waste Act* (Canada), the long-term management of used fuel will be performed by the Nuclear Waste Management Organization that was recently created under the *Nuclear Fuel Waste Act* (Canada). There is a risk that the Nuclear Waste Management Organization may not be able to recover its GST because it may not be considered to be carrying on a commercial activity. There is also the added risk that the trust will have to pay GST on trust withdrawals that it will not be able to recover because the trust is also not carrying on a commercial activity. If either of these situations occur, the Corporation estimates that its costs for the funding of long-term management of used fuel would increase by approximately $167 million for the disallowed GST calculated on a present value basis as of January 2004. OPG and the Nuclear Waste Management Organization are in discussions with the federal tax authorities with a view to obtaining the appropriate remedy.

Regulation

Ontario's Electricity Industry

Legislation

The *Electricity Act, 1998* (Ontario) (the "Electricity Act"), implements the fundamental principles of the restructuring of Ontario's electricity industry. These include the separation of the competitive parts of the industry (generation and retail) from the natural monopoly parts of the industry (transmission and distribution), the establishment of an independent electricity market operator and the implementation of non-discriminatory access to transmission and distribution systems.

The OEB Act, 1998 expands the jurisdiction and mandate of the OEB in the regulation of the electricity and natural gas markets. In its role as regulator of the Ontario electricity market, the OEB has broad powers relating to licensing, rate regulation and market supervision. The OEB is obligated to implement the Province's policy directives, including directives concerning conservation matters as well as those intended to address existing or potential abuses of market power by energy sector participants or matters that relate to the Market Power Mitigation Agreement directive. Upon the petition of any party or interested person, the Province may require the OEB to review all or any part of an order that the OEB has issued.

The purposes of the Electricity Act and the objectives of the OEB pursuant to the OEB Act, 1998 are to: facilitate competition in the generation and sale of electricity and to facilitate a smooth transition to competition; provide generators, retailers and consumers with non-discriminatory access to transmission and distribution systems in Ontario; protect the interests of consumers with respect to prices and reliability and quality of electricity service; promote economic efficiency in the generation, transmission and distribution of electricity; facilitate the maintenance of a financially viable electricity industry; promote energy conservation, energy efficiency, load management and the use of cleaner energy sources, including alternative and renewable energy sources, in a manner consistent with the policies of the Province; and to promote communication within the electricity industry and the education of consumers. An additional purpose of the Electricity Act is to ensure that Ontario Hydro's debt is repaid in a prudent manner and that the burden of such debt is fairly distributed.

The key regulatory instruments authorized by the Electricity Act and the OEB Act, 1998 that apply to OPG and its business are: the transfer orders issued by the Lieutenant-Governor in Council; the Market Rules made by the IMO; and OPG's generation, wholesaler and retailer licences issued by the OEB. Elements of the restructuring of Ontario's electricity industry are in place, including the regulations and Market Rules that govern the competitive wholesale and retail electricity markets. These regulations and Market Rules include technical provisions dealing with participation in the markets, the delivery of energy through the IMO-controlled grid and the provision of certain ancillary services and the IMO's financial markets arrangements.

Since Market Opening, a number of amendments have been made to both the Electricity Act and the OEB Act, 1998 through the following legislation: Bill 58, the *Reliable Energy and Consumer Protection Act, 2002* and Bill 210, the *Electricity Pricing, Conservation and Supply Act, 2002*, plus related regulations. Bill 58 focused on the conduct of retailers selling to consumers who use less than 150,000 kWh of electricity annually. This has little direct impact on OPG. Bill 58 also increased the investigative power of the IMO Market Surveillance Panel ("MSP"). The changes implemented by the *Electricity Pricing, Conservation and Supply Act, 2002* and the *Ontario Energy Board Amendment Act (Electricity Pricing), 2003* are discussed in more detail under the following sections "*Background – Evolution of Ontario's Competitive Electricity Market", "Business of OPG – Risk Factors – Restructuring of Ontario's Electricity Industry"* and *"Government Regulation"*. In summary, these statutes and related regulations have enacted a number of amendments to the regulation of the Ontario electricity market. One of the main changes was the fixing of the price at which low-volume and other designated consumers purchase electricity. Sometime prior to May 1, 2005 a new pricing regime for these consumers will be developed by the OEB.

Transmission Congestion and Transition Rate Option

The *Electricity Act, 1998* (Ontario) mandates non-discriminatory access to transmission and distribution facilities by providing that every transmitter or distributor must provide generators, retailers and consumers with non-discriminatory access to its transmission or distribution systems in Ontario in accordance with its licence. See *"– Regulation – Ontario's Electricity Industry – Market Power Mitigation – Rebate Mechanism and Transitional Price"*.

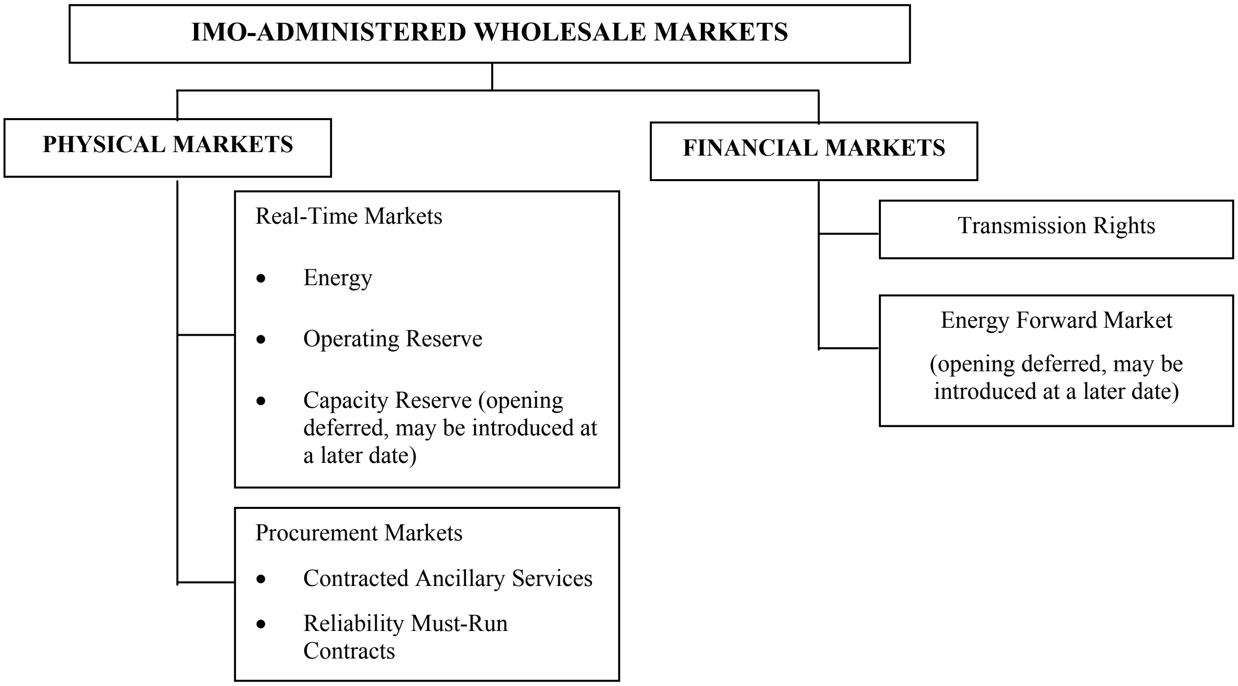
A uniform market-clearing price within Ontario is calculated on a congestion-free basis. Settlements for generators and consumers are based on metered energy multiplied by the uniform market-clearing price. If transmission constraints or line losses require less expensive generation to be removed from production and more expensive generation to produce more electricity, the constrained generators will be compensated by an additional payment, which will be charged to consumers. The IMO collects and publishes locational pricing data to determine the extent of congestion in the Ontario market and will recommend whether to move to some form of congestion pricing as part of the market evolution process. Depending on the extent of congestion, this change could result in locational pricing, in which individual market clearing prices would be established for various locations in Ontario. Interconnections with other jurisdictions are treated as separate zones from the rest of Ontario and separate zone prices apply when an interconnection is constrained.

In anticipation of Market Opening, a regulation was enacted by the Province known as the "Transition Generation Corporation Designated Rate Options". Under this regulation, OPG is required to provide transitional price relief following Market Opening to certain customers, effectively providing them with an extension of various pricing options that they had received prior to Market Opening. These contracts have the effect of hedging the price at which OPG sells a portion of its electricity. The maximum length of the program is four years. A provision of $210 million on the TRO contracts was recorded in the first quarter of 2002 based on the estimated future loss on these contracts. The provision was determined at that time using management's best estimates of the forward price curve for electricity, wholesale electricity market fees, impact of decontrol on these contracts, interruptions of volume, and the recovery of Market Power Mitigation Agreement rebates. The provision for the TRO contracts was established based on expectations of meeting decontrol targets within three years of market opening. OPG no longer expects to meet the decontrol targets necessary for TRO contracts to expire after three years. As a result, an additional charge of $30 million related to the fourth year of the TRO contracts was recorded in 2003.

The IMO

The IMO functions both as independent system operator, ensuring overall system reliability and stability through control of physical dispatch, and as independent market operator, the clearing house for the settlement of spot transactions by suppliers and purchasers of electricity participating in the IMO wholesale market.

The IMO-administered wholesale market for energy services consists of: (i) both physical markets, relating to the dispatch and pricing of electricity; and (ii) financial markets, which are focused on financial risk management associated with the exposure to spot market energy prices and to transmission constraints. The following chart provides an illustration of the products and services that are available in the IMO-administered market, as well as some additional products and services which may be introduced at a later date.



The IMO-administered physical electricity markets consist of both real-time and procurement markets: real-time markets for energy and operating reserve, and, if implemented, a capacity reserve market, and procurement markets for additional generation-related services to maintain reliability of the transmission grid. For more information about these markets, see *"Business of OPG – Regulation – Ontario's Electricity Industry – The IMO"*.

Spot market prices in the IMO-administered real-time market fluctuate significantly as a result of a number of influences, including domestic market demand, operating reserve requirements, generation availability and the volume of imports from and exports to interconnected markets. The highest spot market prices are set during periods of peak demand and are typically set by plants with the highest marginal cost at that point in time. This is usually natural gas generators or facilities with limited energy generation available. During off-peak periods, spot market prices are generally set by plants with a lower marginal cost of production, such as coal-fired generation. Spikes in spot prices are very often weather and capacity driven. Due to the fact that the Ontario market is interconnected with other energy marketplaces, prices in Ontario are also influenced by conditions in those markets.

The IMO is conducting a consultation process on market evolution to address several key market design issues and implement changes, including the following: (i) implementation of a day ahead market; (ii) optimization of dispatch over multiple intervals rather than the current process which optimizes dispatch every five minutes; (iii) consideration of some form of locational marginal pricing ("LMP") (LMP is used by both New York and PJM, and is being proposed in the Midwest ISO); and (iv) proposals to deal with both short-term and long-term resource adequacy.

The IMO-administered financial markets are intended to provide wholesale market participants with risk management opportunities through the trading of transmission rights and energy forward contracts.

Transmission rights are sold to market participants by the IMO in scheduled auctions. The operation of the transmission rights market is intended to provide market participants with a financial hedge for congestion when importing or exporting energy. Congestion occurs at a time when the IMO receives more bids or offers than can be accommodated given the available limits on transmission capacity between Ontario and the interconnected market at an inter-tie. When the flows of electricity are such that an inter-tie reaches its capacity, it results in variations in energy prices on either side of the inter-tie. Transmission rights are a financial risk management instrument and do not provide a market participant with priority access to transmit electricity across an inter-tie. Transmission rights may be purchased or sold notwithstanding that the purchaser or vendor is not offering to purchase or sell electricity across an inter-tie. They do, however, entitle a purchaser to a payment from the IMO in the event of congestion at the inter-tie.

Under the Electricity Act the IMO is authorized to make and enforce the Market Rules which are necessary to perform its function and administer the IMO-controlled market. Bill 210 gave the Minister of Energy the power to revoke rule amendments before they are implemented. Each market participant is obliged to follow the Market Rules in accordance with its participation agreement with the IMO and its OEB licence.

The IMO acts as a clearing house for the settlement of spot market transactions as well as designated physical bilateral contracts between IMO market participants and sends invoices to market participants. Credit risk in the settlement process is managed by IMO rules requiring all authorized market participants to satisfy requirements for creditworthiness, with all participants sharing the risk of loss on a market participant's payment default on a *pro rata* basis.

The IMO-administered physical electricity markets include real-time markets. The spot markets for energy and operating reserve are both part of the real-time markets that are administered by the IMO. The energy market deals with offers to sell and bids to purchase electricity. Operating reserve is generating capacity that can be called upon or demand that can be reduced on short notice by the IMO, for example, to replace scheduled electricity supply that is unavailable as a result of contingencies such as unexpected outages of generating facilities, or deal with unanticipated increases in demand. The IMO establishes separate prices for the energy market and the operating reserve markets. The IMO jointly optimizes these two markets to produce dispatch instructions and prices intended to result in the most cost-effective overall solution for the market. The description below of how the IMO establishes the market clearing prices of electricity and operating reserve does not include adjustments that result from the interaction of the energy and the operating reserve markets. Furthermore, the following description is based upon the assumption that there are no constraints in the transmission system. If there are constraints in the transmission system, further adjustments are made to dispatch instructions and the compensation paid to generators.

In the energy market, offers to sell specified quantities of electricity at specified prices for each hour of a given day (the "dispatch day") are made by generators in Ontario and elsewhere. Intermittent and small generation facilities may be designated as "non-dispatchable", in which event they receive the market clearing price for all electricity generated by the facility, without the need to submit an offer to sell to the IMO. All other generators are "dispatchable" and are only dispatched if their offer is accepted.

Consumers may similarly submit bids that specify the maximum price that the consumer is willing to pay for electricity. Such consumers are considered to be "dispatchable". If a consumer submits such a bid, when the price of electricity exceeds the price in its bid, the consumer must reduce its electricity usage based on dispatch instructions from the IMO. All other consumers are "non-dispatchable". Non-dispatchable consumers do not submit bids and pay the hourly market clearing price for all electricity consumed by them.

Offers from generators and bids from consumers are provided to the IMO in advance of the dispatch day and may be changed within certain time limits. For each five-minute interval, the market clearing price is set by the price of the next available bid or offer that has been submitted to the IMO to meet the next MW of demand. This price can, therefore, be set by an offer submitted by a dispatchable generator or by a bid submitted by a dispatchable consumer. The IMO also establishes an hourly market clearing price, which is the arithmetic average of the five-minute interval market clearing prices during that hour. All dispatchable generators and dispatchable consumers whose offers or bids are accepted by the IMO receive or pay the five-minute interval market clearing price for electricity generated or consumed, based upon metered quantities. All non-dispatchable generators and non-dispatchable consumers receive or pay the hourly market clearing price for electricity generated or consumed by them based on metered quantities.

The operating reserve markets establish market clearing prices that are paid to parties whose offers to provide operating reserve are accepted by the IMO. As mentioned above, these prices are affected by the interaction between the energy market and the operating reserve markets.

The IMO maintains the reliability of the transmission grid through ancillary services (operating reserve, reactive support/voltage control service, black start capability and automatic generation control) and must-run contracts for local reliability. Ancillary services other than operating reserve are purchased by the IMO through procurement markets. Must-run contracts for reliability can involve compensating a generator for staffing and keeping a unit in production mode as a support or contingency regardless of the market-clearing price on the spot market. The cost of providing these services is charged by the service provider to the IMO, which passes the expense on to consumers through uplift charges. The IMO arranges suppliers for these services through a competitive tendering process. Contracts are limited to terms of 18 months or less for contracted ancillary services and 12 months or less for must-run contracts. These suppliers receive compensation for costs for being available, out-of-pocket costs, opportunity costs when providing the service and any other compensation deemed fair by the appropriate regulatory authorities.

In its capacity as the independent electricity system operator, the IMO entered into operating agreements with transmission owners who continue to operate their systems, subject to IMO direction and regulation by the OEB. The IMO assesses transmission system constraints in its dispatch of energy and manages congestion and line losses using the established Market Rules. It also administers the grid connection requirements applicable to market participants connected to the transmission system and identifies any long-run security and adequacy requirements by conducting periodic long-run assessments. In addition, the IMO advises the OEB and participates in OEB proceedings that consider new transmission investment proposals. Market participants are free to present transmission investment proposals to the OEB at any time, with or without a supporting assessment from the IMO. The cost of new transmission system investments will be included in a network service charge unless the OEB determines that there is an identifiable beneficiary who should pay.

The IMO also collects the transmission service charges designed to recover the transmission owners' OEB-approved revenue requirements and disburses these revenues to the transmission owners. Consumers of significant amounts of electricity can, individually or as a group, build their own generation facilities and thereby avoid paying certain transmission charges. In many circumstances, consumer-owned generation will also allow those consumers to avoid IMO uplift charges. This can give rise to the construction of new generation capacity that would not be economic if it were not for this avoidance of transmission charges and IMO uplift charges.

Through its independent Market Surveillance Panel, the IMO will identify and report on any inappropriate market conduct and market inefficiencies. In its monitoring report for the first 18 months of the market issued December 2003, the MSP stated that there was no evidence of market power abuse. The IMO collects from and provides information to market participants relating to the current and future electricity needs of Ontario and the capacity of the integrated power system to meet those needs.

If the IMO determines prior to issuing dispatch instructions that market responses will not eliminate an under-generation condition, it can declare an emergency operating state to resolve the conditions. The IMO also has the authority to suspend the IMO-administered market if certain emergency circumstances exist or are imminent, such as a failure of the market system or a major blackout. The market cannot be suspended solely because the market price has reached the maximum market clearing price or some demand has been curtailed. Each market participant is required to file with the IMO its emergency plans to assist the IMO in dealing with an emergency operating state. The IMO will endeavour to restore market operations as soon as the conditions requiring suspension are resolved.

The OEB licenses the IMO and monitors its operations. The OEB also issues directions to the IMO and hears appeals of certain actions or decisions of the IMO, including any amendments to the Market Rules. The IMO's operating costs are recovered through OEB-approved fees which are levied on the market participants. Bill 210 gave the Minister of Energy the power to review rule amendments before they are implemented and oversee certain rates approved by the OEB.

OEB's Licensing Process and Industry Codes

The OEB has developed licences for electricity generation, transmission, distribution, wholesale and retail. It has also developed several associated codes for retailing, transmission and distribution. On October 31, 2003, the OEB issued a renewal generation licence to OPG that will remain in force until October 30, 2023. OPG also has a wholesaler licence and a retailer licence, which will remain in force until January 2006 and September 2005, respectively.

Market Power Mitigation

When the electricity market opened for competition, OPG owned (excluding assets leased to Bruce Power) approximately 73% of the generating supply options in Ontario. To address the possibility that OPG could exercise market power after the commencement of Market Opening, the Province approved a framework known as the "market power mitigation" framework to protect the interests of consumers while ensuring an orderly and gradual transition to a long-run industry structure in which OPG's share of generating capacity available to the Ontario market is substantially reduced. The market power mitigation obligations applicable to OPG are set out in the conditions to OPG's generation licence.

Rebate Mechanism and Transitional Price

The majority of OPG's expected energy sales in Ontario are subject to an average annual revenue cap of 3.8 cents per kWh, which is not adjusted for changes in the consumer price index, fuel prices, labour or other price increases. During each 12 month period following May 1, 2002 (i.e. Market Opening), if the average spot market price as calculated under the framework exceeds 3.8 cents per kWh, OPG is required to pay a rebate, which after April 30, 2003 is paid quarterly to the IMO, equal to the difference between the average spot market price and 3.8 cents per kWh, multiplied by the quantity of electricity to which the threshold applies in that period, referred to as the contract required quantity ("CRQ"). This rebate amount is subject to reductions in the event of system price spikes, the carrying forward of a rebate credit from prior years and *force majeure* events. The IMO is responsible for allocating the rebate to Ontario consumers in the case of customers above the 250,000 kWh per year threshold and in other cases to the OEFC, on the basis of energy withdrawn from the IMO-controlled grid.

This rebate mechanism applies only to OPG. It does not guarantee that the spot market price will be 3.8 cents per kWh, nor does it set the price for individual consumers. Rather, OPG is free to offer electricity into the IMO market at whatever price it chooses, as are competing generation companies. The rebate mechanism applies to OPG's production up to the CRQ and is calculated as if OPG had produced at least the CRQ regardless of OPG's actual production. The CRQ has been predetermined for the period up to 2004 and varies over that period within a range of approximately 102 to 106 TWh, subject to reduction with the approval of the OEB as OPG decontrols its generation capacity. The OEB has determined that both the Bruce and Mississagi transactions qualify as decontrol therefore the CRQ currently stands at 81.4 TWh.

As noted earlier, effective from May 1, 2003, customers above the 250,000 kWh per year threshold have been entitled to receive a quarterly rebate payable through the IMO which is fixed at 50% of the amount by which the average spot price exceeds 3.8 cents per kWh.

In addition, the Province enacted a regulation to provide transitional price relief to current customers of OPG that had contracted to purchase some or all of their electricity requirements under one or more of pricing options historically provided by Ontario Hydro to certain customers. Forty-five large power consumers with 68 sites have accepted this transitional price relief. OPG is required to effectively offer for sale to these customers a volume of energy based on their consumption of special rate power. The anticipated volume is approximately 5.4 TWh in the first year after May 1, 2002; 3.6 TWh in the second year and 1.8 TWh in each of the third and fourth years. The maximum length of the program is four years. See *"Regulation-Ontario's Electricity Industry-Transmission Congestion; Transition Rate Option"*.

Decontrol of Capacity

The market power mitigation framework requires OPG to relinquish effective control of some of its generating capacity.

Upon OPG's request, the OEB is required to make a determination as to whether a transaction represents the transfer of effective control and can therefore count towards OPG's decontrol targets and reduce the CRQ. Transfers will not count towards OPG satisfying its decontrol targets or reducing the CRQ if: (i) such transfer would result in any one transferee controlling more than 25% of the total relevant capacity in Ontario; or (ii) OPG and the transferees have in place any on-going arrangements which facilitate interdependent behaviour.

In keeping with its decontrol obligations, on May 11, 2001 OPG leased its Bruce A and B nuclear generating stations to Bruce Power L.P. In a transaction that closed in February 2003, the ownership of Bruce Power L.P. was transferred to a consortium comprised of TransCanada PipeLines Limited, BPC Generation Infrastructure Trust, the Ontario Municipal Employees Retirement Board and Cameco Corporation. OPG also sold the Mississagi hydroelectric stations to Mississagi Power Trust in a transaction which closed on May 17, 2002. Both of these transactions were subsequently found to qualify as decontrol by the OEB, and were counted towards OPG's decontrol milestones.

The Province has recently stated that there will be no further sale of publicly owned generation assets. No additional details have been provided regarding the impact of this position on OPG's mandated requirement to decontrol.

Import Restrictions

OPG's ability to import power from interconnected markets is restricted to 7.24 TWh in the winter season and 6.58 TWh in the summer season. These restrictions are intended to ensure that OPG does not exercise market power by controlling imports across the interconnection points. These import limits will be increased upon the in-service date of new or upgraded interconnection facilities. Ontario's inter-tie capacity is currently approximately 4,000 MW. Hydro One is obligated under its licence conditions to use its "best efforts" to expand inter-tie capacity to neighbouring jurisdictions by approximately 2,000 MW within 36 months of May 1, 2002. Hydro One has obtained the approval of the OEB to begin their portion of the work to expand the existing Ontario-Québec inter-tie by 1,250 MW. Hydro-Québec, however, is still in the process of resolving its regulatory issues for the project and therefore the outcome of this project is still uncertain. In addition, Hydro One is completing the installation of phase-shifting transformers and an autotransformer at its interconnection with the Michigan power grid. Depending upon how the phase shifters will be operated, this equipment should provide the ability to better control energy flows at that interconnection point and, indirectly, at the interconnection with the New York power grid. The equipment is expected to increase the available transfer capability between Ontario and Michigan by between 500 MW and 600 MW. Hydro One has also initiated work on a new Niagara area transmission line to increase the New York transfer capability by about 800 MW for service in 2007.

Operating Reserve

Under the market power mitigation conditions of its generation licence, offers made by OPG to provide operating reserve to the IMO are capped. The level of this cap includes the actual cost of providing operating reserve, such as additional operating and maintenance costs, additional fuel costs, additional opportunity costs and a reasonable rate of return on incremental capital. OPG will receive the clearing price for operating reserve regardless of how that price is set. OPG is required to offer all available capacity into the operating reserve market, consistent with good utility practices.

Expansion of Inter-Tie Capacity

To encourage the supply of electricity into Ontario from the interconnected markets, Hydro One, as a condition of its OEB licence, is obligated to use its best efforts to expand inter-tie capacity by approximately 2,000 MW within 36 months of Market Opening, subject to governmental and regulatory approvals and environmental assessments. Hydro One has been involved in various inter-tie expansion projects, including projects that would: (i) increase the available transfer capability with Michigan, by 500 – 600 MW, in conjunction with International Transmission Company; (ii) expand existing inter-tie capacity with Québec, by 1,250 MW; and (iii) create a new Niagara area transmission line to increase the New York transfer capabilities by about 800 MW. The Michigan and Quebec inter-tie expansion projects have been delayed and it is not known if these expansions will take place. The Niagara project has a planned in-service date of 2007.

Energy Regulation

The *OEB Act, 1998* (Ontario) authorizes the OEB to operate as an independent, quasi-judicial, regulatory agency of the Province and to regulate the electricity industry. The Corporation is licensed by the OEB as an electricity generator, retailer and wholesaler. See *"– Ontario's Electricity Industry – Legislation"* and *"Ontario's Electricity Industry – OEB Licensing Process and Industry Codes"*.

The *National Energy Board Act* (Canada) established the National Energy Board (the "NEB"), an independent Federal regulatory agency that regulates, among other things, the construction and operation of international and designated interprovincial power lines and the export of electricity into the United States. OPG holds permits issued by the NEB for the export of electricity into the U.S. The most significant of these permits provides for the export of up to 25 TWh of power in any consecutive 12-month period.

In the United States, regulation of electricity is shared among FERC and the Department of Energy, at the Federal level and the State Public Service Commissions, at the State level. FERC has jurisdiction over transmission used in interstate commerce and rate-setting authority over wholesale transactions. The Department of Energy issues presidential permits authorizing the construction of international power lines and permits authorizing the export of electricity. The State Public Service Commissions have rate-setting authority over retail transactions and citing authority for most new facilities. Each State also retains the authority, either through its Public Service Commission or its legislature, to determine if and when open retail access will be permitted.

OPG has entered into various master agreements with a wide range of counterparties pursuant to which it can transact for the purchase and sale of electricity in the U.S. northeast and midwest or trade financial derivative products. OPG's ability to transact under these agreements is limited by various factors such as the creditworthiness of the counterparty. OPG, through its U.S. subsidiary, has obtained the appropriate FERC authorization to sell at market-based rates. As a result, OPG is able to purchase transmission services and is able to transmit energy to buyers not directly connected with the Ontario electricity system at the U.S. border. This authorization allows OPG to buy its own transmission rights and to make purchases and sales of electricity, either sourced in Ontario or elsewhere, directly to wholesale or retail customers in the United States at market-based rates. This authorization provides OPG with expanded access to the U.S. market, however, to date OPG has not made use of this authorization. See *"– Regulation".*

FERC's decision to extend market-based rate authority to OPG's U.S. subsidiary has been challenged by Consumers' Energy of Michigan. The decision has been upheld on rehearing, but is currently subject to review by the DC Circuit of the U.S. Court of Appeals. However, the market-based rate authority remains in effect while any appeals are heard.

Nuclear Regulation

The *Nuclear Safety and Control Act* (Canada) (the "NSC Act") created the Canadian Nuclear Safety Commission (the "CNSC") and authorized it to make regulations governing all aspects of the development and application of nuclear energy. The most significant powers given to the CNSC are in the licensing area. A person or organization may only possess or dispose of nuclear substances, or construct, operate and decommission its nuclear facilities in accordance with the terms of a licence issued by the CNSC. The licence specifies conditions that licensees must satisfy in order to demonstrate that the licensee is qualified to carry out the activities authorized by the licence. International and national standards in relation to matters such as safeguards and radioactive emissions are examples of conditions incorporated into station licences.

A fundamental principle in nuclear regulation is that the licensee bears the responsibility for safe operation with the CNSC setting safety objectives, in areas such as radiation protection and physical security for all nuclear generating stations and the transport of radioactive materials. The CNSC audits the licensee's performance against the objectives. The CNSC has also issued guidance documents to assist licensees in complying with regulatory requirements as these apply to safety system design and operation of CANDU nuclear generating stations. Requirements spelled out in these guidance documents have been incorporated into the design and operating documents for OPG's nuclear generating stations.

The NSC Act is the product of an update of regulatory requirements by the Federal Government in relation to the effective regulation of nuclear energy in Canada. The NSC Act grants to the CNSC the power to act as a court of record, the right to require financial guarantees for nuclear waste management and nuclear facility decommissioning as a condition of granting a licence, order-making powers and the right to impose monetary penalties for license infractions. The NSC Act also grants the CNSC the power to require periodic re-certification of nuclear operators and to set requirements for various nuclear facility security measures. The Act also provides for increased emphasis on environmental matters, including a requirement that licence applicants make adequate provision for the protection of the environment. The NSC Act grants the CNSC licensing authority for all nuclear activities in Canada, including the issuance of new licences to new operators, the renewal of existing licences and amendments to existing licences.

The *Nuclear Liability Act* (Canada) (the "NLA") imposes absolute liability on a licensed operator of a nuclear generating station for any damage to property of, or personal injury to, the public arising from a nuclear incident other than damage resulting from sabotage or acts of war. As such, the NLA protects suppliers of nuclear fuel and components used in nuclear reactors.

The NLA requires all operators of nuclear generating stations in Canada to purchase nuclear liability insurance from the Nuclear Insurance Association of Canada in specified amounts. Currently, the NLA requires a nuclear operator to maintain, for each of its nuclear stations, insurance up to a limit of $75 million per incident against the liability imposed under the NLA. Under Part I of the NLA, an operator is liable for all damages resulting from a nuclear incident. If in the opinion of the Governor in Council, an operator's liability could exceed $75 million in respect of a nuclear incident, or it would be in the public interest to do so, the Governor in Council must proclaim Part II of the NLA as applicable in respect of a nuclear incident. Under Part II of the NLA, an operator's liability would be effectively limited to the amount of such insurance and the Governor in Council may authorize additional funds to be paid by the Federal Government as may be specified in an order. The NLA is currently under review, which could result in a requirement for increased insurance coverage. See *" – Insurance"*.

Since the regulation of nuclear energy could have transboundary impacts, Canada has become a signatory to various international conventions relating to nuclear energy and emergency responses and is bound by conventions that it has ratified. In addition, the CNSC has entered into a five-year, bilateral information exchange and co-operation agreement with the U.S. Nuclear Regulatory Commission, which provides among other things, for the prompt, reciprocal notification of reactor safety problems that could affect both U.S. and Canadian nuclear generation facilities.

All of OPG's nuclear power reactor operating licences were reissued as of April 1, 1999 when OPG acquired the generation business of Ontario Hydro. All nuclear power reactor operating licences have since been renewed pursuant to the *Nuclear Safety Control Act* (Canada) by the CNSC. During 2003, the CNSC granted five-year renewals of operating licences for the Darlington and Pickering B generating stations. Pickering A, which has been laid up since the end of 1997, was granted a licence renewal for a period of 2 years in 2003. Renewal of these licences is subject to a variety of terms and conditions relating to the operation of the facilities. The Pickering A operating licence currently contains a clause which restricts operation of three of four units subject to approval of the CNSC to restart those units. During 2003, the CNSC approved the restart of Unit 4 at the Pickering A nuclear generating station.

See also "– *Generation Operations – Nuclear Operations – Nuclear Waste Management and Decommissioning - Provisions for Nuclear-Related Costs*" for information about the *Nuclear Fuel Waste Act* (Canada)".

Regulation of Water Rights

Hydroelectric generation requires ongoing access to an adequate water supply on reasonable terms. The physical availability of water is affected by numerous factors including variations in precipitation, sublimation and evaporation. Rights to and restrictions on the use of water are determined through international treaties, interprovincial agreements, federal and provincial legislation, common law and leases, licences, permits and agreements with the Federal Government, the Province, neighbouring provinces, municipalities, other utilities and other water users.

There are three main federal and provincial statutes governing OPG's water rights or use of water in Ontario, being: (i) the *Public Lands Act* (Ontario) which grants jurisdiction to the Ministry of Natural Resources ("MNR") to regulate the management, sale and disposition of Ontario's public lands and forests. Pursuant to the *Public Lands Act* (Ontario), OPG has water power leases, water lot leases, licences of occupation, land use permits and Crown leases for the purpose of generating electricity; (ii) the *Lakes and Rivers Improvement Act* (Ontario) which regulates the management and use of the lakes and rivers of Ontario. This statute is administered by the MNR and provides for the preservation and equitable exercise of public rights and natural amenities over water. The MNR authorizes the design, construction, operation, maintenance and safety of structures on lakes and rivers in

Ontario such as dams, bridges and docks; and (iii) the *Navigable Waters Protection Act* (Canada) which regulates the construction of facilities that may impact or affect navigation on a navigable waterway.

International Rivers

Seven of OPG's hydroelectric generating stations are directly or indirectly supplied by two major international waterways, the Niagara River and the St. Lawrence River, and are subject to treaties with the United States relating to water use. Those stations represent approximately 48% of OPG's in-service hydroelectric capacity and approximately 56% of OPG's 2003 hydroelectric generation.

A 1909 treaty with the United States (the "Boundary Waters Treaty") governs the rights, obligations and interests of Canada and the United States over all lakes, rivers and connecting waterways along the international boundary. A 1950 treaty between Canada and the United States (the "Niagara Diversion Treaty") supersedes specified sections of the Boundary Waters Treaty with respect to diversions of the Niagara River for power generation purposes. The Boundary Waters Treaty has been terminable by either party on 12 months' notice since 1915 and, in 2000 the Niagara Diversion Treaty became terminable by either party on 12 months' notice. Given the significant interests of both countries in the water rights which are contingent on the continued effect of these treaties, OPG does not expect Canada or the United States to exercise their termination rights under either treaty in the foreseeable future. OPG is not aware of any negotiations concerning formal extensions or replacement treaties.

Subject to specified prior uses, each of these treaties grants Canada and the United States equal rights to use waters made available for power generation. Additional water is allocated to Canada under the Niagara Diversion Treaty and is used by OPG's Niagara hydroelectric operations to account for water that is diverted to the Niagara system via Lake Superior from the James Bay watershed by the Ogoki and Long Lac Diversions in northern Ontario. Canada's rights and obligations under each treaty that relate to power generation on the Niagara River and the St. Lawrence River are exercised by the Province, which has in turn granted certain of those rights to OPG under legislation, authorizations and lease agreements.

OPG's operations on the Niagara and St. Lawrence rivers are conducted in accordance with memoranda of understanding with the New York Power Authority which provide for co-ordinated generation at their respective facilities and for certain cost sharing arrangements.

OPG's use of water from the Niagara River, the Welland River, the Welland Canal and the St. Lawrence River is monitored and controlled by international organizations established under the applicable treaty. These organizations have the authority to set operational limits for flows and elevations associated with water power generation in order to maintain adequate water availability for domestic and sanitary uses and for navigation and to minimize negative impacts on other users of these rivers. The amount of water available from the Niagara River for power generation is subject to agreements under the Niagara Diversion Treaty to ensure adequate flow over Niagara Falls for scenic purposes during the tourist season.

Niagara Region

Through a combination of statutory rights, authorizations, agreements and a lease agreement with the Niagara Parks Commission that expires in 2056 (subject to certain renewal rights), OPG has the right to divert water from the Niagara River and construct facilities to generate power. OPG has four stations that use water diverted from the Niagara River and two stations that use water from the Welland River and Welland Canal. Together, these stations represent approximately 33% of OPG's in-service hydroelectric capacity and approximately 36% of OPG's 2003 hydroelectric generation.

Under a Niagara Parks Commission agreement which, subject to certain rights of the Province, expires in 2009, the Rankine hydroelectric generating station, owned by Fortis Ontario Inc. ("Fortis"), is entitled to withdraw water from the Niagara River, as part of Canada's share of water under the Niagara Diversion Treaty, in an amount equal to that required for the generation of electrical power to a daily average not exceeding 100,000 electrical horsepower (provided that at no time shall the amount produced exceed such daily average by more than three percent). Under an agreement between OPG and Fortis, Fortis consents to OPG using Fortis' water entitlement. OPG is currently negotiating with Fortis regarding these water rights.

The DeCew Falls stations use water that is transported along the Welland Canal from Lake Erie by the St. Lawrence Seaway Management Corporation under an agreement that expires in 2008, but which is renewable to 2038.

St. Lawrence River

The R.H. Saunders station near Cornwall represents approximately 15% of OPG's in-service hydroelectric capacity and approximately 19% of OPG's hydroelectric generation in 2003. By statute and a water lot lease, the Province has granted to OPG the right to use water from the International Rapids section of the St. Lawrence River for power generation, subject to an agreement between Canada and the Province that requires the Province to construct, maintain and operate the works in accordance with conditions or orders imposed by Canada or the international organization established under the Boundary Waters Treaty. Canada has the right, upon notice and after unsuccessful arbitration, to take over the operation of and title to, the R.H. Saunders station in the event of a breach of the agreement by the Province.

Interprovincial Rivers

Four of OPG's hydroelectric stations are located on the Ottawa River which forms part of the Ontario-Québec border. These stations represent approximately 13% of OPG's in-service hydroelectric capacity and approximately 14% of OPG's 2003 hydroelectric generation. Three of OPG's Ottawa River stations are subject to 999 year leases with each of the Province of Ontario and the Province of Québec and the fourth is subject to a water power lease with the Province of Ontario which is renewable, subject to certain conditions, through to 2031. OPG's use of water from the Ottawa River basin is subject to guidelines established by a board comprised of government and industry representatives.

The operations of certain of OPG's stations in northwestern Ontario can impact users in Manitoba and are subject to guidelines and directions provided by a board comprised of Ontario and Manitoba government representatives. These sites are discussed under "*– Interior Rivers"*.

Interior Rivers

Fifty-four of OPG's 65 hydroelectric stations (including 29 green energy), representing approximately 39% of OPG's in-service hydroelectric capacity and 31% of OPG's hydroelectric generation in 2003, are located on 22 other Ontario river systems. OPG holds water power leases, Crown leases and licences with the Province on the river systems that supply 36 of these stations. These leases and licences have expiry dates (including renewals) ranging between 2012 and 2075. Certain of these leases provide that the leased property and any fixed improvements, including the generating stations and the dams, will revert to the Province on the expiry of the lease. The 36 stations covered by these licences and leases represent approximately 38% of OPG's in-service hydroelectric capacity. Approximately 1% of OPG's in-service hydroelectric capacity comes from the remaining 18 stations. Eight of these stations are located on the Trent and Rideau Canals and are operated pursuant to licences from the Federal Government.

OPG's use of Ontario's interior watersheds is constrained by restrictions contained in certain water power leases and licences. OPG also operates within voluntary guidelines and formal water management plans under the *Lakes and Rivers Improvement Act* (Ontario), established on a watershed basis in consultation with the MNR, federal fisheries authorities and stakeholders such as recreational and commercial users, local communities, environmental groups and First Nations.

Port Facility Security

On December 12, 2002, the International Maritime Organization, of which Canada is a member, adopted a number of amendments to the Safety of Life at Sea Convention, 1974 (the "Convention"), intended to significantly enhance the international framework for the deterrence, prevention and detection of acts that threaten security in the marine transportation sector. All International Maritime Organization members are required to have adopted these amendments by July 1, 2004. In order to give effect to the Convention, the Canadian government has proposed new regulations titled the "*Marine Transportation Security Regulations*". Transport Canada has informed OPG that the proposed regulations will apply to OPG's Lakeview, Nanticoke and Lambton coal-fired generating stations. OPG has been working with Transport Canada to complete all requirements to meet the proposed regulations and has submitted port security assessments and draft security plans as required by the proposed regulations.

Freedom of Information Act (Ontario)

Effective December 8, 2003, OPG became subject to the *Freedom of Information Act* (Ontario). OPG was exempt from this legislation since April 1, 1999. Under this legislation, anyone can request information that is under the custody and control of OPG. Therefore OPG may now be required to disclose information that was not previously available to the public, including information that pre-dates the effective date on which OPG became subject to this legislation. There is certain information that OPG is not required to disclose, such as information (i) that is commercially sensitive; (ii) the release of which would qualify as an unjustified invasion of personal privacy; or (iii) the release of which could compromise the security of OPG's generation facilities. Decisions made by OPG to either release information or not disclose some or all of the information requested, on the basis that such information is exempt from disclosure, are subject to an appeal process which is overseen by the provincially appointed Information Privacy Commissioner.

Public Sector Salary Disclosure

On April 15, 2004 the *Public Sector Salary Disclosure Act,* 2004 (Ontario) received Royal Assent. This Act requires Hydro One Inc., OPG and their subsidiaries to disclose salaries and benefits paid to employees who earned $100,000 or more. On April 28 2004, OPG disclosed such salary information for the years 1999 through 2003.

Environmental Regulation

OPG is subject to federal, provincial and municipal environmental laws. These include laws relating to the control of discharges to air, land and water, as well as the investigation and remediation of contaminated property and the management and disposal of materials and hazardous wastes, including nuclear wastes. The Federal Government has also entered into various international environmental agreements, some of which may affect OPG, such as the Kyoto Protocol. See "*– Environmental Matters*".

The principal Provincial environmental laws that apply to OPG are Ontario's *Environmental Protection Act* (the "EPA"), the *Ontario Water Resources Act* (the "OWRA"), the *Environmental Assessment Act* (the "EAA"), the *Dangerous Goods Transportation Act* (which incorporates, by reference, the Federal *Transportation of Dangerous Goods Act Regulations*) and the *Technical Standards and Safety Act*, as well as regulations made under these statutes, including EPA Regulation 346 (air emissions), EPA Regulation 215/95 amended to 501/99 (the "MISA Regulation"), EPA Regulation 347 amended to 501/01 (general waste management), EPA Regulation 356 (ozone depleting substances or "ODS"), EPA Regulation 362 (polychlorinated biphenyls or "PCB" wastes), EPA Regulations 153/99 and 397/01 (which regulate SO_2 and NO_x emissions from OPG's fossil-fuelled generating stations and the procurement and use of emission reduction credits and allowances), EPA regulation 396/01 (which regulates nitric oxide emissions at the Lakeview fossil generating station) and EPA Regulation 127/01 amended by 196/01 (which requires all facilities in the electricity sector to monitor and report on the emissions into the atmosphere of a number of substances).

The EPA and regulations made thereunder regulate the management and disposal of wastes (including hazardous and non-hazardous wastes), discharges and spills into the natural environment, liquid effluent discharges into water and emissions into the air. OPG is required under the MISA Regulation to ensure that liquid effluents discharged directly into water bodies are within specified toxicity limits. The OWRA imposes obligations to protect the quantity and quality of water in Ontario. Specifically, the OWRA forbids any discharge of material into water that may impair the quality of water.

There is an existing Director's Order issued to OPG by Ontario's Ministry of Environment and Energy pursuant to the EPA. The Director's Order requires OPG to measure SO_2 and NO_x emissions using Continuous Emissions Monitors. See *"– Environmental Matters – Overview"* and *" – Contaminated Land"*.

The principal Federal environmental laws that apply to OPG are the *Canadian Environmental Protection Act, 1999* ("CEPA, 1999"), the *Fisheries Act* and the *Navigable Waters Protection Act*. CEPA, 1999 regulates the use, storage, import and export of toxic substances, such as Ozone Depleting Substances and PCBs. The *Fisheries Act* (Canada) prohibits the alteration or destruction of fish habitat and prohibits the deposit of any substance that would be harmful to water that may be inhabited by fish. An authorization under the *Fisheries Act* (Canada) is required for the construction of a project that would result in the harmful alteration or destruction of fish habitat.

Under the *Navigable Waters Protection Act* (Canada), approvals are required for the construction of works that interfere with the public right of navigation and the alterations to the originally approved work.

The Federal *Canadian Environmental Assessment Act* requires an environmental assessment of certain projects such as those requiring certain federal regulatory actions, including CNSC licences for the construction of nuclear facilities or approval of the disposal of nuclear substances and approvals for projects affecting navigable waters or that impact fisheries. The *Canadian Environmental Assessment Act* may apply to some of OPG's facilities, including its nuclear facilities and hydroelectric modifications or developments that affect navigation or fish habitat. An environmental assessment under the *Canadian Environmental Assessment Act* was completed for the restart of Pickering A, for dry storage at Bruce B and Pickering A, and for the used fuel dry storage facility project at Darlington; and one is currently underway for Phase II of the Pickering used fuel dry storage facility. See "*– Generation Operations – Nuclear Operations – Nuclear Recovery*".

Ontario's *Environmental Assessment Act* traditionally required that only projects initiated by public bodies (which were listed in the regulations and included OPG) be assessed and approved under Ontario's *Environmental Assessment Act*. Therefore, OPG was historically required to conduct environmental assessments of all projects, including new developments or facility modifications and obtain Ministry of Environment approval, unless otherwise exempted. Private sector companies were not subject to Ontario's *Environmental Assessment Act*, except if a project was specifically designated for an environmental assessment. New regulations (O. Reg. 116/01) under Ontario's *Environmental Assessment Act* have changed the environmental assessment requirements to apply equally to projects by both public and private sector electricity companies. These new regulations divide projects into three general categories, depending on the predicted impact of the project on the environment, with either no environmental assessment requirements, screening level environmental assessment requirements, or requirements for a full environmental assessment.

Environmental Matters

Overview

OPG's activities involve risk of adverse consequences to the environment and are therefore subject to extensive governmental regulation. See *"– Regulation – Environmental Regulation"* and *"– Risk Factors – Regulatory Risks - Environmental Risks"*. OPG is committed to becoming a sustainable energy development company. In accordance with this commitment, OPG strives to continually improve environmental performance in its operations and in its relations with stakeholders.

OPG's Sustainable Energy Development Policy commits OPG to meeting all applicable legislative requirements and voluntary environmental commitments, integrating environmental factors into business planning and decision-making and applying the precautionary principle in assessing risks to human health and the environment. This policy also commits OPG to maintain comprehensive environmental management systems ("EMSs") consistent with the ISO 14001 standard. OPG became one of the first electric utilities in North America to obtain ISO 14001 registration for the EMSs at all its generating stations in 1999/2000. This registration is obtained and kept current annually through independent audits.

OPG monitors emissions into the air and water and regularly reports the results to various regulators, including the Ministry of Environment, Environment Canada and the CNSC. OPG has implemented internal monitoring, assessment and reporting programs to manage environmental risks such as air and water emissions, discharges, spills, radioactive emissions and radioactive wastes. Further, OPG makes regular reports to the Ministry of Environment with respect to its contaminated land remediation program.

In addition to the regular reports made to various regulators, the public receives frequent communications from OPG regarding OPG's environmental performance through community-based advisory groups representing communities surrounding OPG's major generating stations, annual environmental performance reports, community newsletters, open houses and OPG's website.

The generation of electricity can also directly and indirectly contribute to ecosystem stresses and potential biodiversity losses through, for example, loss and fragmentation of terrestrial habitat or the modification of water flow regimes. In recognition of such potential impacts, OPG has implemented a Biodiversity Policy with the goal of demonstrating that we can co-exist with nature without causing or contributing to the long-term decline of species, or the habitats upon which they depend, on a regional basis.

Sustainable Development Initiatives

OPG is committed to being a sustainable energy company. OPG's goals in this regard include meeting all legislative requirements and voluntary environmental commitments with the objective of moving beyond compliance; maintaining environmental management systems consistent with the ISO 14001 environmental management specifications; integrating environmental and social factors into planning, decision-making, and business practices; applying environmental considerations to operating decision making; developing the use of renewable energy and energy efficient technologies; and measuring and communicating our progress towards achieving sustainable development.

The conservation of biological diversity is an integral part of our sustainable development efforts and is an essential pre-condition to achieving sustainability. Accordingly, OPG undertakes biodiversity assessments and where needed, implements a variety of biodiversity management plans at our major plants and land-holdings, as well as in several strategic locations across southern Ontario.

OPG is one of Ontario's largest green energy producers, primarily from wind, and low-impact hydroelectric sources, with a total of 133MW of green energy certified by EcoLogo^{M}. For example, OPG operates a 1.8 MW wind turbine at its Pickering facility, which is the largest wind turbine in North America. OPG, in partnership with Bruce Power, also operates the Huron Wind farm, capable of generating 9 MW of electricity.

Management of Air Emissions

OPG is required to comply with provincial and federal air quality requirements in connection with discharges into the air from its generating stations.

Hydroelectric Operations

There are no material environmental concerns relating to air emissions from hydroelectric operations.

Fossil Operations

The burning of fossil fuels gives rise to a number of air emissions, principally sulphur dioxide ("SO_2"), nitric oxide ("NO_x") and carbon dioxide ("CO_2"), as well as mercury and particulate matter such as dust and ash.

Acid Gas Emissions

Acid gas (SO_2 and NO_x) emissions contribute to acid rain and legislation specifically regulating such emissions has been in force in Ontario since the mid-1980s. A number of government initiatives have been implemented or recently announced regarding air emissions and others can be anticipated to deal with this issue.

OPG's fossil generation is currently limited because Ontario's environmental regulations limit OPG's annual SO_2 and NO_x emissions. In order to meet these regulatory requirements, OPG has implemented air management initiatives to monitor and reduce emissions from its fossil generating stations. For a discussion of the regulatory regime applicable to SO_2 and NO_x air emissions as well as of OPG's initiatives to address these regulations, see "*– Generation Operations – Fossil Operations – Effective Generation Limits and Air Emissions*".

Mercury Emissions

Mercury emissions from coal-fired generating stations have emerged as an environmental and health issue. Initiatives are underway in both Canada and the United States to assess and regulate mercury emissions from the electricity generating sector. Specifically, the United States Environmental Protection Agency has announced draft two possible versions of Mercury Rules for the electricity sector with compliance in 2007 or 2010 depending on which rule is promulgated. In Canada, coal-fired utilities, including OPG, began a two-year voluntary mercury monitoring and reporting program in 2003. This program will provide mercury emission data in support of the development of a Canada-wide Standard for Mercury, led by the Canadian Council of Ministers of the Environment (CCME). The CCME announced its intent to proceed with the development of a standard by 2005 with compliance required by 2010. There is considerable uncertainty as to what specific limits will be established in part because current technologies under development are expensive, unproven in commercial applications and their long term operating performance is unknown. At this stage, OPG has been actively involved in researching and funding the development of mercury emission control technologies, specifically co-funding a U.S. Department of Energy sponsored program assessing carbon injection technology and CANMET Energy Technology (Ottawa) program assessing additives to enhance mercury capture. OPG also continues to work with government, stakeholders, academics and industry in assessing the issue of mercury emissions.

Greenhouse Gas Emissions

The primary greenhouse gas resulting from OPG's operations is CO_2. OPG has been managing its greenhouse gas ("GHG") emissions since 1995, when Ontario Hydro first committed to stabilize net CO_2 emissions by 2000 at the 1990 levels of 26 million tonnes. OPG has operated under this voluntary CO_2 target since 2000 (see "*– Generation Operations – Fossil Operations – Effective Generation Limits and Air Emissions"*). To meet its year 2000 voluntary target, OPG reduced its net CO_2 emissions by 12.6 million tonnes through internal energy efficiency projects and through the purchase of emission reduction credits from third parties at a cost of $13 million, or approximately one dollar per metric tonne. In order to meet the voluntary limit of 26 million tonnes of CO_2 in 2001, 2002 and 2003, OPG would need to acquire CO_2 emission reduction credits of 11.1, 10.7 and 10.5 million tonnes respectively. In that effort, OPG has purchased 10.7 million tonnes of CO_2 emission reduction credits at a cost of $14.0 million. In addition, OPG has contracts in place for purchase of credits in 2004 -2007 for approximately 3.4 million tonnes at a cost of approximately $5.8 million.

In 2003, OPG initiated a review of its voluntary GHG emission target in light of the proposed Federal Government's Climate Change Plan, the continuing uncertainty surrounding the entry into force of the Kyoto Protocol and the Province's recently announced plans to close Ontario's coal-fired generating stations. Given these uncertainties, including the potential impact of the closing of the coal-fired plants on OPG's GHG emissions profile, essentially reducing it to zero beyond 2007, OPG has decided to delay further investment in CO_2 emission reduction credits and plans to extend the "true-up period" (or the period in which we can apply credits to earlier years) for its voluntary target to 2010. The extension of the true-up period to 2010 allows OPG to use internally created post-2007 GHG emission reduction credits to offset GHG emissions above the voluntary target in the period 2001 to 2007.

OPG has and will continue to assess opportunities to make modifications to equipment and operating controls that improve coal combustion heat rate and implements energy efficiency programs which can result in lower CO_2 emission rates.

OPG reports GHG emissions under O.Reg.127/01. The National Pollutant Release Inventory (NPRI) recently announced that OPG (and other emitters) would be required to report to the NPRI on GHG emissions commencing from the year 2004. Also commencing in 2004, OPG (as well as all major emitters) will be required to comply with the Federal Government's mandatory reporting programme with respect to GHG emissions that exceed specified thresholds. OPG voluntarily reports GHG emissions to the Climate Change Voluntary Challenge and Registry Inc. program.

The Federal Government's Climate Change Plan calls for a 55 million tonne reduction in GHG emissions beginning in 2008 from large industrial emitters, which includes the electricity sector. Negotiations to define the reductions required from specific sources began in 2003. OPG is participating in these negotiations and will revise its GHG emissions strategy as required to meet any future regulatory requirements. The Federal Government has attempted to reduce the economic impact of limits on GHG emissions by large industrial emitters by committing that industry will have access to CO_2 emission reduction credits at a cost of no more than $15 per metric tonne, and by limiting the credit volume risk to no more than 15 % below the Federal Government's projected emissions for the Ontario electricity sector in 2010. See "*– Risk Factors – Regulatory Risks - Environmental Risks*".

Nuclear Operations

As a condition of licensing, all nuclear operations are equipped with radiation emission monitors to ensure that emissions are below regulated limits. All nuclear operating licences stipulate limits on the rates at which radionuclides may be emitted to the air from each nuclear site. These derived emission limits are site-specific and approved by the CNSC. Since the 1970s, actual radiological air emissions from OPG's nuclear facilities have remained a small fraction of the regulatory limit.

OPG reports annually on the results of its radiological environmental monitoring programs at each nuclear generating station by estimating the radiation exposure to persons who are assumed to live immediately outside the station fence. This theoretical dose has consistently been estimated to be a small fraction of the public dose regulatory limit set by the CNSC. The results of these monitoring programs are reported on an annual basis to the CNSC, the Ministry of Environment and the municipalities in which the nuclear stations are located. They are also reported quarterly in the nuclear report cards that are made available to the public.

All Operations

OPG has a corporate policy to manage ozone-depleting substances ("ODS") in a safe, environmentally responsible and cost-effective manner. ODS, specifically chlorofluorocarbons ("CFCs"), are used in refrigeration systems and can damage the ozone layer if emitted to the atmosphere. The Federal Government has proposed regulations that will accelerate the transition from CFC's to alternative substances and technologies beginning in 2005. OPG has agreements in place with the federal and provincial governments that allow for the orderly transition to non-ODS refrigerants.

Management of Water Effluent

OPG is required to comply with federal, provincial and municipal water quality requirements in connection with the discharge of condenser cooling water and other water effluents from OPG's generating stations.

Fossil Operations

OPG has implemented programs to manage the water effluent from its fossil generating stations and is in material compliance with Ontario's MISA Regulation (O. Reg. 215/95 as amended).

OPG uses chlorine to control zebra mussels at some of its fossil stations. OPG's exemption from the provincial regulatory limits in the power sector MISA Regulation relating to chlorine-induced toxicity from chlorine used to control zebra mussels expired in July 2002. OPG has spent approximately $15 million in the aggregate for dechlorination of effluent from fossil facilities, including upgrades to the chlorination systems. This work was completed in advance of the July 2002 deadline.

Nuclear Operations

OPG has implemented programs to manage the water effluent from its nuclear generating stations. At the end of 2001, OPG had spent about $120 million to install new equipment at its nuclear generating stations in order to comply with the power sector MISA Regulation. Like the fossil stations, the nuclear operations use chlorine to control zebra mussels. See *"– Fossil Operations"* above. OPG has spent approximately $7.0 million at its nuclear facilities to achieve compliance with the MISA Regulation chlorine-toxicity requirements which came into force in July 2002.

OPG has replaced the brass condensers at Pickering B nuclear station, which were a source of copper/zinc contamination from that station. The Pickering A brass condensers will be replaced before they are returned to service.

Contaminated Land

The Ministry of Environment and Energy issued a Director's Order (the "Order") in September 1997 requiring that Ontario Hydro report on tritium contamination at the Pickering nuclear generation station and assess potentially contaminated lands at its other generating facilities. In response to the Order, all of OPG's known and potentially contaminated properties were ranked according to potential risk to human health and the environment in order to develop priorities for corrective action. Focusing on the high priority sites, OPG prepares an annual site assessment plan, which is submitted to and approved by the Ministry of the Environment. The site assessment plan provides a progress report and plans for the current year to address the Order. All commitments made in the site assessment plans for the past six years have been met.

As of January 2004, the Ministry of the Environment had provided written confirmation that OPG had fulfilled its site assessment requirements under the Order for all high, medium and low priority sites and the

Ministry lifted the Order in March 2004. Assessment and remediation work is continuing under OPG's voluntary environmental site assessment program.

One additional site, a reservoir not covered by the Order, Lake Gibson, has been assessed under a parallel voluntary program. The assessment report and third party review are presently under review by the Ministry of the Environment. OPG estimates the present value of assessment and remediation of all contaminated sites (including Lake Gibson) at approximately $40 million over the next four years and such amount is fully reserved under the OPG environmental provision. The need for remediation of the Lake Gibson reservoir has not been established since OPG is not the source of the contamination nor is this the recommendation of recently – conducted site assessments. See "– *Regulation – Environmental Regulation*".

In addition to the above, costs for demolition and site clean up of facilities at Kipling Avenue, Orde Street and 700 University Avenue in Toronto, including assessment and remediation, are estimated at $7 million. These costs are reserved under the OPG environment provision.

Management of PCBs

PCBs have been widely used for a number of industrial applications and particularly as a coolant and insulating fluid in electrical equipment (for example, in transformers and capacitors). Since 1977, PCB production has been prohibited in North America. In 1998, Ontario Hydro made a policy commitment to eliminate 81% of its in-storage PCB waste and in-service high-level PCBs by December 31, 2005 and the remainder of in-service high-level PCBs by December 31, 2015. As of December 31, 2003, the amounts of PCBs at the fossil, nuclear and hydroelectric stations were 508 tonnes, 804 tonnes and five tonnes, respectively, consisting of in-service high-level PCB transformers and small amounts of PCB waste to be shipped for destruction. Revisions to the federal PCB regulations anticipated for the fall of 2004 are expected to call for the phase-out of all high-level (over 500 parts per million) in-service PCB equipment by the end of 2007 and all low-level (between 50-500 parts per million) PCB equipment by the end of 2014. The proposed changes will have no material effect on OPG.

At OPG's hydroelectric facilities, transformers with high-level PCBs have been removed from all facilities. There are no power transformers known to be in-service with low-level concentrations of PCBs. Minor quantities of PCB and PCB-contaminated equipment that remains in-service consists of lighting ballasts, cables, bushings and capacitors. PCB wastes were removed from OPG's hydroelectric facilities for decontamination and/or destruction commencing in 1995. There are approximately five tonnes of PCB-contaminated equipment remaining at hydroelectric facilities. An estimate for the cost of disposal is $25,000.

At its fossil stations, OPG has removed substantially all low-level PCB equipment, materials and oil from in-service operating equipment. OPG plans to remove all in-service high-level PCB equipment from its fossil operations and ship such waste along with the currently-stored PCB waste for destruction by 2006. The total cost for replacement of this equipment is approximately $14.6 million. This cost and the ability to complete the removal of PCBs will depend on the availability of PCB-destruction facilities, such as the Swan Hills facility in Alberta.

Substantially all of the previously accumulated in-storage PCB waste from OPG's nuclear stations has been destroyed. Units 1, 2 and 3 of the Pickering A nuclear station have in-service high-level PCB transformers. OPG plans to phase out these transformers by the end of 2007 to meet anticipated changes to the federal PCB regulations or as part of the Pickering A return to service project, pending the provincial government's decision on whether to continue with the return to service project. The PCB transformers from Pickering A Unit 4 were removed from service and shipped for destruction during the Unit 4 return to service project. The estimated cost of the phase-out of the remaining Pickering PCB transformers is $5.0 million. There is one small PCB capacitor at Pickering B nuclear station and no in-service PCBs or PCB wastes at the Darlington nuclear station.

OPG's total projected cost for the remaining PCB phase-out and equipment replacement at its fossil and hydroelectric stations and the Pickering A nuclear station is $19.6 million. Remaining costs of PCB phase-out and destruction, estimated at $6 million, are received under the environment provision. Bruce Power has returned e high-level PCB transformers to operational service at the Bruce A station and is responsible for the transformers while they remain in service.

Nuclear Waste Management and Decommissioning

OPG has adopted certain management practices and planning assumptions to satisfy its nuclear waste management and decommissioning obligations. See *"– Generation Operations – Nuclear Operations – Nuclear Waste Management and Decommissioning"* and *"– Risk Factors – Generation Risk - Nuclear Operations"*.

Legal Proceedings

OPG is currently a party to and its assets are the subject of various legal proceedings and OPG is aware that there are further proceedings contemplated. OPG does not believe that any of these is likely to have a materially adverse impact on the Corporation on a consolidated basis.

Risk Factors

Each of the following risk factors could have a material adverse effect on OPG's business, financial condition, operating results and prospects.

Operational Risk

Operational Risk is the risk of direct or indirect loss resulting from external events or from inadequate or failed internal processes, people, equipment and systems. OPG identifies and assesses operational risk through a risk-self assessment process. In addition to identifying and reporting on operational risk, self-assessments are used to develop risk mitigation plans. Business units are responsible for implementing a risk self-assessment and mitigation framework based on corporate standards.

Operational risk related to electricity trading and sales is quantified using a mathematical model based on banking industry practices. OPG plans to quantify operational risk across the company, in conjunction with standardized process for collecting loss data, key risk indicators and self-assessment results.

OPG's top operational risks presently identified include generation availability risk and project management process risk related to the refurbishment of the Pickering A nuclear facility.

Generation Risk

OPG is exposed to the market impacts of uncertain output from its generating units or generation risk. The amount of electricity generated by OPG is affected by such risks as fuel supply, equipment malfunction, maintenance requirements, and regulatory and environmental constraints. To mitigate earnings volatility due to generation risk, OPG enters into multiple short-term and long-term fuel supply agreements and long-term water use agreements, manages fuel supply inventories, and follows industry practices for maintenance and outage scheduling. In addition, OPG ensures regulatory requirements are met, particularly with respect to licensing of its nuclear facilities, and manages environmental constraints utilizing programs such as emission reduction credits.

OPG is exposed to considerable technology risk around the aging of the nuclear fleet. Technology risks that could lead to significant impacts on the production capability or operating life of these assets are not fully predictable and OPG attempts to identify these risks through on-going management review and assessments, internal audits and from experience of nuclear units around the world. The impact of these risks is assessed and mitigation strategies are developed and executed.

OPG maintains general public liability, property and business interruption insurance, subject to deductibles. The occurrence of a significant event that is not fully insured or indemnified against, or the failure of a party to meet its indemnification obligations, could materially and adversely affect OPG's consolidated results of operations and financial position.

Nuclear Operations

OPG developed its current nuclear recovery plan in 1997 with a group of independent nuclear experts. Its successful implementation depended on many factors, including: no unanticipated deficiencies in its nuclear operations or greater-than-anticipated deterioration to its nuclear generating assets; no material changes to the current regulatory structure governing nuclear generation; the ability of OPG to hire, train and retain senior management and other qualified personnel; the ability of OPG to increase productivity; the ability of OPG to implement management and operational changes and the sufficiency of the allocated funds for implementing the nuclear recovery plan.

In early 2003, amidst concerns about declining performance at Picking B and increasing maintenance backlogs at both plants, OPG undertook a reassessment of the nuclear business plan. The underpinning of the 2003 assessment was a detailed review of the material condition risks at Pickering B and Darlington and benchmarking analysis on both staff levels and costs. It concluded that the production expectations laid out in that 1997 Nuclear Recovery Plan were not achievable. See "*Business of OPG – Nuclear Operations – Nuclear Recovery*".

There can be no assurance that Pickering B can fully attain and sustain top performer status given the material condition issues of the plant. It is more likely that Darlington would be in a position to achieve and sustain high performance, unless the issues relating to its feeders become more severe. In the event that OPG does not fully realize the intended benefits of implementing its current nuclear recovery plan, electricity production from OPG's nuclear facilities may be lower than anticipated; operating costs may be higher than expected; and additional regulatory requirements or constraints could be imposed. Any one of these results could have a material adverse effect on OPG's business, operating results, financial condition or prospects.

The staged restart of the four units at OPG's Pickering A nuclear station has been a key corporate initiative. In February 2001, the CNSC released its decision with respect to an environmental assessment under the *Canadian Environmental Assessment Act*, which allowed the CNSC to proceed with consideration of OPG's licence application through the normal public hearing process under the NSC Act. Subsequently, OPG's licence application for the re-start of Pickering A was approved by the CNSC on November 5, 2001. The amended licence permits OPG to return the four Pickering A reactors to service, subject to the completion of specified improvements and upgrades. The amended licence has been renewed and is valid for a further period of two years, until June 30, 2005. Unit 4 has been re-started and is operating.

OPG has comprehensive inspection and testing programs in place in order to ascertain the physical condition of its nuclear generating stations. In particular, it has undertaken an ongoing program to assess the condition of its steam generators, fuel channels and related infrastructure such as feeder pipes as part of its nuclear recovery plan. As a result of these programs, OPG has identified equipment life-cycle issues, such as steam generation tube corrosion, feeder pipe wall thinning and pressure tube/calandria tube contact. These conditions were generally anticipated in the design but experience has shown that the rate of degradation is higher than anticipated. The associated life cycle plans for these components are intended to monitor and mitigate the degradation. In addition, as no nuclear generating station utilizing CANDU technology has yet completed a full life cycle, there is a risk that there could be unforeseen technological or equipment issues that are materially adverse to the business, operating results, financial condition or prospects of OPG. Accordingly, there can be no assurance that OPG will not have to incur significant expenditures for repairs or replacements. To address these issues, OPG may need to increase preventative maintenance programs and allow for more outage time than currently is planned. Such repairs or replacements could have a material adverse effect on OPG's business, operating results, financial condition or prospects. OPG's success will depend, in part, on its ability to maintain an economically efficient portfolio of nuclear generation assets. See *"– Generation Operations – Nuclear Operations – Generating Facilities"*.

One CANDU nuclear reactor outside of Ontario has recently experienced feeder pipe cracking. OPG has not experienced any feeder pipe cracking at any of its nuclear facilities, but it continues to closely monitor this issue.

OPG is subject to extensive federal regulation with respect to its nuclear operations. Risks of substantial liability, as well as the potential for significant increased costs of operations, arise from the ownership and operation of nuclear generating stations, including, among other things, structural problems, increasing security requirements to cover factors such as physical security threats, equipment malfunctions, the storage, handling and disposal of radioactive materials and uncertainties with respect to the technological and compliance costs associated with nuclear waste management and decommissioning. An increase in any of these costs may have a material adverse effect on OPG's business, operating results, financial condition or prospects. OPG has implemented risk management strategies such as the reactor physics strategy with respect to changed requirements of the CNSC with respect to reactor physics codes (see "*Generation Operations – Nuclear Operations – Reactor Physics*"), but there can be no assurance that such risks can be minimized.

A major accident at a nuclear installation anywhere in the world could impact the regulation of OPG's activities or the future prospects for nuclear generation. See "*– Regulation – Nuclear Regulation*" and "*– Generation Operations – Nuclear Operations*".

OPG is also subject to Federal regulation of its nuclear waste management practices. Management of nuclear waste poses unique risks. Failure to comply with the applicable requirements could have a material adverse impact on OPG. In addition, changes in federal regulation could result in costs in addition to the substantial costs currently incurred by OPG for nuclear waste management which could have a material adverse effect on OPG's business, operating results, financial condition or prospects. See "*– Regulation – Nuclear Regulation*".

The Federal Government enacted Bill C-27, the *Nuclear Fuel Waste Act*, in 2002. There is no facility for the permanent disposal of nuclear fuel waste currently in operation in Canada, nor has the CNSC licensed any such facility. OPG's nuclear waste management and decommissioning obligations are subject to numerous factors, including: assumptions regarding implementation schedules, cost estimates, discount rates and the rate of return earned on segregated funds established to satisfy these obligations; the tax-deductibility of OPG's contributions paid to the segregated funds should OPG's tax-exempt status change; the tax-exempt status of income earned on the segregated funds; the sale tax treatment of expenditures incurred by the Nuclear Waste Management Organization; changes in Federal policy or regulation regarding nuclear waste management and decommissioning (including, but not limited to, financial assurance requirements, program standards, the method of and future availability of long-term waste management and other assumptions under OPG's nuclear waste management and decommissioning programs); and the degree of control OPG will have over the scope and implementation of its programs. Many of these factors relate to matters which are untested or for which there is no significant degree of certainty. Changes in any of these factors could materially adversely affect OPG's business, operating results, financial condition or prospects. See "*- Generation Operations – Nuclear Operations – Nuclear Waste Management and Decommissioning*".

OPG and the Province have entered into the Ontario Nuclear Funds Agreement, under which the Province limits OPG's financial exposure in relation to certain used fuel management costs. This agreement is effective as of April 1, 1999. Under the principles of this agreement, OPG continues to be responsible for significant nuclear waste management liabilities. If those costs exceed current estimates, OPG's liability for nuclear waste management can increase significantly but its liability for the long-term storage and disposal of nuclear used fuel waste will effectively be capped. The Province does not limit OPG's financial exposure to decommissioning and low and intermediate level waste management costs; accordingly, OPG will be liable to make up any deficiency in the funding of these costs. OPG is also fully responsible for all incremental costs relating to the management of used fuel bundles in excess of 2.23 million bundles. Northern community opposition to geologic disposal of used fuel and potential station community opposition to prolonged on site used fuel storage may impede the ability of the Nuclear Waste Management Organization to develop plans acceptable to major stakeholders. In addition, community support for centralized storage of low and intermediate level waste at the Western Waste Management Facility at the Bruce site may erode due to reduced OPG presence at the site. A program is underway in conjunction with local communities aimed at the potential for development of a long-term low and intermediate-level waste management facility at the Bruce site. See "*– Generation Operations – Nuclear Operations – Nuclear Waste Management and Decommissioning*" and "*- Strategic Risks– Ownership by the Province; Potential Conflicts of Interest with the Province and Related Parties*".

The level of OPG's contributions to the segregated funds established under the Ontario Nuclear Funds Agreement will be impacted, potentially materially, by any changes to decommissioning and waste management reference plans and associated cost estimates, the tax treatment of the funds and the requirements of the Ontario Nuclear Funds Agreement and the *Nuclear Fuel Waste Act* (Canada).

OPG's contributions to the segregated funds are deductible under the proxy tax regime currently applicable to the Corporation and certain of its Canadian subsidiaries. In addition, any related investment income earned on these funds is treated by OPG as being exempt from proxy tax. The trust fund for the long term management of used fuel, governed by the *Nuclear Fuel Waste Act* (Canada), may be subject to taxation under the *Income Tax Act* (Canada) on some or all of its investment income. However, the Federal Government has indicated to the provinces of Ontario, Quebec and New Brunswick that it will take appropriate measures to ensure that such income is exempt from tax provided certain conditions are met – see "*– Relationship with the Province and Others – Taxation of Provisions for Future Nuclear-Related Costs*". This is no assurance that this will in fact occur. The other segregated funds to be established by OPG under the Ontario Nuclear Funds Agreement will be custodial funds. These funds are not taxed as a separate entity under the *Income Tax Act* (Canada). Since the Corporation owns these funds, any related investment income earned will be attributed to the Corporation and accordingly such income will be exempt from taxation under the *Income Tax Act* (Canada) because the Corporation is exempt from tax under this Act. If OPG loses its tax-exempt status, there can be no assurance that the fund contributions would continue to be deductible in determining the tax liability of the Corporation or its subsidiaries, nor that the investment income earned on these funds would continue to be tax-exempt – see "*– Relationship with the Province and Others - Relationship with the Province*" and "*- Stranded Debt and Proxy Taxes*". If these contributions were not deductible in determining OPG's tax liability, OPG's annual tax liability would increase materially by approximately $150 million per year for the period to 2008, based on an average of the applicable tax rates. If the investment income were also taxable, the contributions would increase from $454 million annually to approximately $800 million annually for the years to 2008. If the estimated cost of nuclear waste management and decommissioning increases beyond current estimates, OPG's liability and these contributions would increase further. In addition, if the NWMO is unable to receive the same sales tax treatment that the Corporation would be entitled to receive if this organization had not been established, OPG's liability and these contributions would increase even more – see "*– Relationship with the Province and Others – Taxation of Provisions for Future Nuclear –Related Costs*". While the outcome cannot at this stage be determined, the Corporation has been engaged in discussions with the relevant taxation authorities to review various alternative structures or arrangements to negate these potential negative tax results.

Although reserves of natural uranium are relatively abundant, the market price and available supply of uranium concentrates may be volatile from time to time. OPG currently uses one contractor to convert its uranium concentrates into uranium dioxide and one independent manufacturer to process uranium dioxide into finished nuclear fuel bundles. These advanced stages of the nuclear fuel supply chain are more susceptible to supply security, price and quality risks. In addition to maintaining inventories of nuclear fuel bundles, OPG has entered into various contractual arrangements to mitigate these risks, but these risks cannot be entirely eliminated. Failure by OPG to obtain adequate supplies of nuclear fuel of satisfactory quality and price could have a material adverse effect on OPG's business, operating results, financial position or prospects. See "*– Generation Operations – Nuclear Operations – Nuclear Fuel Procurement*".

Hydroelectric Generation

Approximately 48% of OPG's in-service hydroelectric capacity depends on water rights derived from treaties between Canada and the United States which are terminable upon 12 months' notice. Although OPG does not expect that Canada or the United States will exercise their termination rights under those treaties in the foreseeable future, there can be no assurance that such termination will not occur. The loss of the ability to generate power at some or all of its facilities could have a material adverse effect on OPG's business, operating results, financial condition or prospects. See "*– Regulation – Regulation of Water Rights*".

OPG pays gross revenue charges to the Province and makes water rental payments to other jurisdictions. Significant increases in gross revenue charges post-2003 and water rentals could have a material adverse effect on OPG's business, operating results, financial condition or prospects. See "*– Relationship with the Province and Others – Stranded Debt and Proxy Taxes*".

The occurrence of dam failures at any of OPG's hydroelectric generating stations could result in significant liability for damages and a loss of generating capacity and repairing such failures could require OPG to incur significant expenditures of capital and other resources. OPG implemented a dam safety program in 1986 to minimize the risks associated with dam failures. The program consists of inspections, assessments and monitoring to detect potential failures and remediate high risk conditions and emergency response plans to minimize the consequences of dam failure. There can be no assurance that the dam safety program will be able to detect potential dam failures prior to occurrence or eliminate all adverse consequences in the event of a failure. Upgrading all dams to enable them to withstand all low probability events, or to ensure strict compliance with the draft dam safety regulations that have been proposed by the MNR under the *Lakes and Rivers Improvement Act* (Ontario), could require OPG to incur significant expenditures of capital and other resources (see "*Generation Operations-*

Hydroelectric Operations-Dam Safety Program"). The consequences of dam failures could have a material adverse effect on OPG's business, operating results, financial condition or prospects.

Fossil Fuel Supply

OPG's coal and gas/oil-fired electricity production is dependent on a secure, reasonably priced supply of coal, natural gas and oil. A number of factors, including mine production problems, rail transportation problems and shipping schedule disruptions could lead to temporary shortages in the supply of coal or increases in the price of coal. These factors could have a materially adverse impact on OPG. Similarly, gas and oil prices and availability can also be affected by numerous factors. Given the fuel mix of OPG's current fleet, the potential impact of gas/oil supply disruptions on OPG is much smaller than the potential impact of coal supply disruptions.

OPG manages fossil fuel supply issues through its contracting strategy, the use of a diversity of sources and through inventory management. Similarly, gas/oil prices and availability risks are managed through a mixture of spot purchases and long-term contracts and the ability to convert floating price contracts into fixed price contracts in a rising market. A reduction of OPG's coal-fired production due to supply issues could have a material adverse effect on OPG.

Reliance Upon Transmission Systems

OPG depends on the capacity and reliability of the transmission and interconnection systems that connect its generators with customers in Ontario and in the export markets. In Ontario, the capacity of such transmission systems is limited under certain conditions and OEB approval is required for its expansion. An element of OPG's strategy is to increase its export of electricity to the U.S. northeastern and midwestern markets. OPG may also face transmission constraints in its target export markets. The capacity and operating reliability of such interconnection, transmission and distribution systems are factors beyond OPG's control and any capacity limitations, restrictions on access or reductions in operating reliability could have an adverse effect on OPG's business, operating results, financial condition or prospects. See " *–OPG's Markets – Interconnected Markets*".

Human Resources and Labour Relations

OPG's ability to implement its corporate strategy is dependent upon its success in attracting and retaining senior management and other personnel and the ability of management and personnel to work together as a cohesive team capable of operating in a competitive environment. OPG must acquire and retain personnel with the skills required to implement new processes and systems and to develop new lines of business. Skilled managers and other employees are also required to ensure that project management and control objectives are satisfied in connection with major corporate initiatives such as the Pickering A restart, and the planned maintenance programs at the nuclear stations. OPG must also develop training programs and succession plans to ensure that its operational staffing needs are met in the future, as the demographics of OPG's workforce poses a significant challenge with approximately 27% of OPG's personnel eligible for retirement by 2008. In some parts of the organization, the risk is much higher. Many of OPG's employees possess experience and skills that will be highly sought-after by competitors in the open market. There can be no assurance that OPG will be able to attract and retain qualified personnel.

The majority of OPG's employees are represented by either the PWU or The Society. The tenor of negotiations with both unions has varied with the economic climate in Ontario, ranging from challenging and difficult to conciliatory and collaborative. This has resulted in complex collective agreements that, historically, have placed constraints on management's traditional flexibility to operate its business in a cost-efficient manner. However, progress is being made in some areas. During the 2001 negotiations with the PWU major changes were made to the wage structures and work assignment portions of the collective agreement. The concept of skill broadening was introduced. Skill broadening allows employees to work outside of their traditional roles by performing a wider range of duties. This is expected to improve productivity and employee job satisfaction. Employees were also placed into three pay bands and the number of job documents was reduced from over 1,000 to approximately 100. In addition, a large number of penalty payments were reduced. These changes will simplify the pay and administrative processes. See *"– Human Resources"*.

Information Technology Infrastructure

OPG's ability to operate effectively and competitively in the Ontario electricity market is in part dependent upon OPG developing and managing a complex information technology systems infrastructure. System failures, or an inability to keep information technology systems aligned with changing market conditions and strategic business objectives, could have a material adverse effect on OPG's business, operating results, financial condition or prospects. The potential impact of IT system failures is mitigated through the implementation of systems and data redundancy, data backups, the use of an alternate data centre for failure of critical IT systems and the implementation of business continuity and disaster recovery plans. OPG has also implemented an IT management framework that is intended to ensure alignment with changing market conditions and that strategic business objectives are maintained. The on-going effectiveness of this framework is assessed through a variety of internal and external reviews.

Effects of Weather

By the nature of its business, OPG's earnings are sensitive to weather variations from period to period. Variations in winter weather affect the demand for electrical heating requirements. Variations in summer weather affect the demand for electrical cooling requirements. Variations in precipitation also affect water supplies, which in turn, affect OPG's generating capacity by limiting OPG's ability to utilize its low-cost hydroelectric generating assets. This may result in increased reliance on other sources of generation.

Financial Risk

Market Risk

OPG's market risk is composed of: (i) commodity risk; (ii) foreign exchange and interest rate risk; (iii) equity risk; and (iv) market liquidity risk (see "- *Commodity Price Risk"*).

Commodity Price Risk

Commodity price risk is the risk that changes in the market price of electricity or of the fuels used to produce electricity, will adversely impact OPG's earnings and cash flow from operations. A variable portion of both OPG's electricity production and overall fuel requirements are exposed to fluctuating spot market prices. To manage the input risk, OPG has implemented a fuel hedging program. In addition to fixed price contracts for fossil and nuclear fuels, OPG periodically employs derivative instruments to hedge its fuels price risk. The percentage of OPG's generation and fuel requirements hedged over the next three years is shown below:

	2004	2005	2006
Estimated generation output hedged [1]	82%	79%	74%
Estimated fuel requirements hedged [2]	96%	80%	78%

1 Represents the portion of megawatt-hours of expected future generation production, including power purchases, for which OPG has sales commitments and contracts including the obligations under its Market Power Mitigation Agreement rebate and transition rate option contracts.

2 Represents the approximate portion of megawatt-hours of expected generation production from all types of facilities (fossil, nuclear and hydroelectric) for which OPG has entered into some form of contractual arrangement or obligation in order to secure either the expected availability and/or price of fuel and/or fuel related services. Fuel in inventory is included. The percentage hedged by fuel type varies considerably and therefore a change in circumstances could have a significant impact on OPG's overall position. OPG's current hedge position for expected coal-fired production in 2005 is approximately 40%.

In addition, the Market Power Mitigation program implemented by the Province of Ontario effectively hedges a portion of OPG's output at $38. OPG actively manages the commodity price risk inherent in its remaining electricity production through the use of derivative instruments.

Open trading positions are subject to measurement against Value at Risk (VaR) limits, which measure the potential change in the portfolio's market value due to price volatility over a one-day holding period, with a 95% confidence interval. VaR utlization ranged between $0.2 million to $1.6 million during 2003 and between

$0.7 million to $2.4 million during 2002. Trading liquidity continues to be constrained in Ontario and interconnected markets due to broader energy market fundamentals as well as uncertainty with the direction of the Ontario electricity market structure. Constrained liquidity continues to limit portfolio hedging and optimization opportunities.

Foreign Exchange and Interest Rate Risk

OPG's foreign exchange risk exposure is primarily against the U.S. dollar and is primarily due to the following two off-setting factors: (i) payment of U.S. dollar denominated transactions such as the purchase of fossil fuels and associated transportation costs; and (ii) receipt by OPG of spot electricity market revenues which have an embedded foreign exchange pricing component, as Ontario spot electricity prices are influenced by fuel prices which are quoted in U.S. dollars but are priced in Canadian dollars. OPG currently manages the net exposure by periodically hedging portions of its anticipated U.S. dollar cash flows according to approved risk management policies.

OPG has interest rate exposure on its short-term borrowings and investment programs. The majority of OPG's debt is fixed on a long-term basis. Interest rate risk arises with the need to undertake new financing and with the potential addition of variable rate debt. Interest rate risk may be hedged using derivative instruments. The management of these risks is undertaken by selectively hedging in accordance with corporate risk management policies.

Equity Risk

Equity risk is the risk of loss due to unexpected changes in the value of equity securities. OPG is subject to equity risk primarily through its pension fund holdings and the nuclear fixed asset removal and nuclear waste management funds, and to equity-type risks through its venture capital investments. Risk oversight is provided by or through formal committees.

Pension Plan

OPG operates a contributory defined benefit pension plan. The OPG pension plan is funded in accordance with the *Pension Benefits Act* (Ontario) and the *Income Tax Act* (Canada). In keeping with this legislation, the current funding requirements of the plan are set out in the most recent funding valuation report filed with the appropriate regulatory authorities. The actuarial funding report filed with the Financial Services Commission of Ontario dated as of April 1, 2002, indicates the pension plan had a surplus of over $262 million. In 2003, OPG made pension fund contributions totalling $153 million, which represented the current pension service cost. OPG estimates that an approximately equal amount will be contributed to the pension fund in 2004. The next actuarial valuation is due by April 2005. If OPG is in a deficit position at the time of the next actuarial valuation, OPG's annual pension contributions could increase significantly.

Credit Risk

Credit risk is the financial risk of non-performance by contractual counterparties. Credit risk excludes any operational risk resulting from a third party failing to deliver a product or service as expected. The majority of OPG's revenues are derived from sales through the IMO-administered spot market. OPG also derives revenue from several other sources including the sale of financial risk management products to third parties.

OPG's credit exposure is concentrated in the physical electricity market with the IMO. Credit exposure to the IMO fluctuates based on timing and is reduced each month upon settlement of the accounts. Credit exposure to the IMO peaked at $1,207 million during 2003. OPG's management believes that the IMO is an acceptable credit risk due to its primary role in the Ontario market. The IMO manages its own credit risk and its ability to pay generators by mandating that all registered IMO spot market participants meet specific IMO standards for creditworthiness and collateralization. Additionally, in the event of an IMO participant default, each market participant shares the exposure pro rata. Given OPG's position in the marketplace, OPG would bear approximately 40% of the exposure residual of collateral and recovery. OPG also measures its credit concentrations with counterparties. OPG's management believes these are within acceptable limits and does not anticipate any material effect on its results of operations or cash flows arising from potential defaults.

The following table provides information on credit risk from energy sales and trading activities as at December 31, 2003:

(millions of dollars)			Potential Exposure [2] for 10 Largest Counterparties	
Credit Rating [1]	Number of Counterparties	Potential Exposure [2]	Number of Counterparties	Counterparty Exposure
AAA to AA-	11	21	-	-
A+ to A-	42	222	6	174
BBB+ to BBB-	78	144	3	37
BB+ to BB-	23	32	1	12
B+ to B-	23	11	-	-
	177	430	10	223
IMO	1	493	1	493
Total	178	923	11	716

[1] Credit ratings are based on OPG's own analysis, taking into consideration external rating agency analysis where available, as well as recognizing explicit credit support provided through guarantees and letters of credit or other security.

[2] Potential exposure represents OPG's assessment of the maximum exposure over the life of each transaction at 95 per cent confidence.

For all other counterparties, OPG's contracts allow for active collateral management to mitigate credit exposures. The contracts provide for a counterparty to post letters of credit or cash for exposure in excess of the established threshold. This could happen as a result of market moves or upon the occurrence of credit-related events. The threshold amount represents credit limits established in accordance with the corporate credit policy. Inability to post collateral is sufficient cause to terminate a contract and liquidate all positions.

Liquidity Risk

OPG operates in a capital-intensive business. Significant financial resources are required to fund capital improvement projects and maintenance at generating stations, and potential expenditures necessary to comply with environmental or other regulatory requirements. In addition, OPG has other significant disbursement requirements including Market Power Mitigation Agreement rebate payments, annual funding obligations under ONFA, pension funding and continuing debt maturities with the OEFC.

The cash requirements currently anticipated beyond the next twelve month period could exceed OPG's current credit facilities. In order to meet these longer-term liquidity requirements and funding commitments, OPG must successfully access extended or additional sources of liquidity. OPG is currently examining options which could include additional payment deferrals, incremental borrowings, or other forms of financial or operating restructuring.

OPG's ability to arrange third-party financing is dependent on a number of factors including: general economic and capital market conditions; credit and capital availability from its shareholder, banks and other financial institutions; maintenance of acceptable credit ratings; and the status of electricity market restructuring in Ontario.

OPG's liquidity is highly dependent on its debt rating and the mark-to-market value of contracts with counterparties. A change in the rating could result in additional collateral requirements with counterparties, depending on the mark-to-market value of the contracts. In particular, where counterparties are in a positive mark-to-market position and OPG is in a negative position, a downgrade of OPG's long-term debt ratings could trigger increased collateral requirements based on the provisions of the contracts.

Regulatory Risks

Restructuring of Ontario's Electricity Industry

Ontario's electricity market has been open to competition since May 1, 2002. Since then, the implementation of the *Electricity Pricing, Conservation and Supply Act, 2002* and the *Ontario Energy Board Amendment Act (Electricity Pricing), 2003* has resulted in certain changes to the structure of the market. On April 15, 2004, the Province announced its proposals for the electricity sector that will result in further changes to that structure. These changes include a combination of regulated and a competitive electricity generation sector, where part of the supply would be price-regulated by the Ontario Energy Board ("OEB"), which for OPG is expected to be its nuclear and base-load hydroelectric assets; a new standard rate plan for homeowners and small businesses to be developed by the OEB; the creation of a new independent body, the Ontario Power Authority, to ensure long-term supply adequacy in Ontario; and the establishment of targets for conservation and the use of renewables. Legislation to implement the proposal is expected to be introduced by June 2004. As a result, it is difficult to predict the effect of these changing market and regulatory conditions on OPG's business, operating results, financial position or prospects.

On the other hand, most neighbouring markets are either mature or developing. New York, New England and PJM markets are relatively mature and stable. MISO, which covers Michigan, other Mid-West states and Manitoba, is in the late design stages of market development and is scheduled to open in December 2004. The design is expected to be compatible with PJM and the other northeastern U.S. markets.

Market Power Mitigation/Decontrol

OPG is subject to certain market power mitigation targets relating to decontrol of generation capacity in Ontario. The fulfilment of these targets will fundamentally change OPG's competitive position in Ontario. Completion of decontrol initiatives within the mandated time frame is also subject to governmental and regulatory approvals which may affect the economics of a proposed transaction and, ultimately, OPG's ability to decontrol generation assets on favourable terms or at all. To date, OPG has leased its Bruce A and B nuclear generating stations to Bruce Power on a long term basis in a transaction which closed in May 2001 and has sold its Mississagi hydroelectric generation stations to Mississagi Power Trust in a transaction which closed in May 2002. The OEB has decided that both of these transactions qualify as decontrol transactions. The failure of OPG to obtain satisfactory terms in further decontrol transactions could have an adverse effect on OPG's business, operating results, financial condition or prospects, including if the OEB does not confirm that a transaction qualifies as a "decontrol" transaction. The status of further decontrol activities is uncertain at this time because the Province has stated that there will be no further sale of publicly-owned generation assets. This is also expected to result in changes to the market power mitigation obligations in OPG's generation licence. See "*Background – Evolution of Ontario's Competitive Electricity Market*".

OPG's revenue will be affected by the rebate mechanism that will apply to a significant amount of electricity until the completion of OPG's mandated decontrol of generation capacity, unless terminated earlier by the OEB. OPG will have to pay a rebate to the IMO if the average spot market price as calculated under the framework exceeds 3.8 cents per kWh for the predetermined amount of electricity. This predetermined amount of electricity has been established up until 2004 and there is no assurance as to the amount that will be applicable to OPG thereafter. Accordingly, OPG's ability to maximize its revenue will be affected by the rebate mechanism. See "–

Regulation – Ontario's Electricity Industry – Market Power Mitigation – Rebate Mechanism and Transitional Price".

There can be no assurance that OPG will not be subject to additional or different market power mitigation obligations in the future which could materially adversely affect OPG's business, operating results, financial condition or prospects. See "*– Restructuring of Ontario's Electricity Industry*".

Government Regulation

OPG's operations are subject to government regulation that may change from time to time. Matters that are subject to regulation include: structure of the electricity market, policy on the future of coal-fired generation, nuclear operations (including regulation pursuant to *Nuclear Safety and Control Act* (Canada), the *Nuclear Liability Act* (Canada) and the *Emergency Plans Act* (Ontario), nuclear waste management and decommissioning, water rentals, environmental matters including air emissions and proxy tax payments. Operations that are not currently regulated may become subject to regulation. Because legal requirements can be subject to change and are subject to interpretation, OPG is unable to predict the impact of such changes on OPG and its operations. See "*– Regulation*".

Environmental Risks

OPG is subject to Federal, Provincial and Municipal environmental regulation. Failure to comply with such laws can subject OPG to significant liabilities, including fines and other penalties. The release of certain substances on or from properties owned, leased, occupied or used by OPG or as a result of OPG's operations has resulted and could further result, in governmental orders requiring the investigation, control and/or remediation of such releases. The presence or release of such substances could have a material adverse effect on OPG's ability to sell its interest in such property or could lead to claims by third parties as a result of the release of such substances.

OPG incurs substantial capital and operating costs to comply with environmental laws and its voluntary environmental programs. The regulatory requirements relate to discharges to the environment; the handling, use, storage, transportation, disposal and clean-up of hazardous materials, including both hazardous and non-hazardous wastes; and the dismantling, abandoning and restoration of generation facilities at the end of their useful lives. See "*– Regulation – Environmental Regulation*".

Any changes in applicable environmental laws, or their enforcement, may impose material additional costs on OPG and could materially impact the value of certain of OPG's assets. These could include, for example, possible changes to regulations relating to air emissions of SO_2, NO_x, CO_2, mercury and particulates, as well as the accelerated phase-out of PCBs and government policy related to the future of coal-fired generation in Ontario. In addition, new approvals or permits or renewals of existing approvals and permits may require environmental assessment and/or result in the imposition of conditions which may be costly. The process for obtaining environmental permits and approvals, including any necessary environmental assessment, can be lengthy, controversial and expensive. OPG could experience difficulty and significantly increased costs to meet new environmental regulation in Ontario, to obtain permits or approvals or to comply with the conditions of new or revised permits or approvals. Such developments could have an adverse effect on OPG's business, operating results, financial condition or prospects.

The amount of electricity that OPG may produce at its fossil generating stations is constrained, in part, by Provincial, Federal international and voluntary acid gas and other emission limits. OPG's ability to sustain or increase fossil generation relative to current levels will depend, in part, on the operation of an effective emission reduction credit trading regime in Ontario. The imposition of further, more stringent, air emission limits or changes to the emissions trading regime could have a material adverse effect on OPG's business, operating results or financial condition. See "*–Generation Operations - Fossil Operations – Effective Generation Limits and Air Emissions*".

OPG's Sustainable Energy Development Policy commits OPG to meet all applicable legislative requirements and voluntary environmental commitments, integrate environmental factors into business planning and decision-making, and to apply the precautionary approach principle in assessing risks to human health and the environment. This policy also commits OPG to maintain comprehensive environmental management systems ("EMSs") consistent with the ISO 14001 standard. OPG became one of the first electric utilities in North America to obtain ISO 14001 registration for the EMSs at all its facilities. This registration is obtained and kept current annually by independent audits.

OPG monitors emissions into the air and water and regularly reports the results to various regulators, including the Ministry of Environment, Environment Canada and the Canadian Nuclear Safety Commission. OPG has implemented internal monitoring, assessment and reporting programs to manage environmental risks such as air and water emissions, discharges, spills, radioactive emissions and radioactive wastes. Further, OPG makes regular reports to the Ministry of Environment with respect to its contaminated property remediation program.

In addition to the regular reports made to various regulators, the public receives frequent communications from OPG regarding OPG's environmental performance through community-based advisory groups representing communities surrounding OPG's major generating stations, annual environmental performance reports, community newsletters, open houses and the dissemination of information on OPG's website.

OPG manages its emissions of sulphur dioxide (SO_2) and nitrogen oxides (NO_x). Emissions are reduced through plant improvements and installation of specialized environmental equipment such as scrubbers to reduce SO_2 emissions, low NO_x burners and selective catalytic reduction equipment to reduce NO_x emissions, and through the purchase of low sulphur fuel. OPG also utilizes emission reduction credits (ERCs) to manage emission levels of nitric oxide within the prescribed regulatory limits and voluntary caps. ERCs are created when a source reduces emissions below the lower of previous actual emissions or the level required by regulation.

Canada has ratified the Kyoto Protocol requiring a six per cent reduction in greenhouse gas emissions from 1990 levels by the period 2008 to 2012. Prior to the ratification of the Kyoto Protocol, OPG voluntarily committed to reduce its greenhouse gas emissions, net of emission reduction credits used, to 1990 levels in 2000 and beyond. OPG expects that the Province will be discussing with the federal government the treatment of the Ontario electricity sector with respect to climate change initiatives. Currently, there is no assurance that such limits would not impose significant costs on fossil electricity generators such as OPG, although the federal government has promised to cap the cost of CO_2 credits at $15 per tonne.

Strategic Risks

Competition

OPG believes its ability to be successful in competitive markets depends upon many factors within and outside its control, including: the entrance of new participants in the Ontario market; the competitive actions of market participants; the extent of self-generation; compliance with market power mitigation obligations; generation performance; changes in the regulatory environment; changes in environmental regulations; access to the interconnected markets; supply, demand and the cost of power in the interconnected markets; weather-related electricity demand levels; wholesale and spot market electricity prices; reliability of supply; customer service and support; and sales and marketing efforts. There can be no assurance that OPG will be able to compete successfully in these circumstances or that competitive pressures will not have a material adverse effect on OPG's business, operating results, financial position or prospects. See "*Background – Evolution of Ontario's Electricity Market*".

Ownership by the Province; Potential Conflicts of Interest with the Province and Related Parties

The Province owns all of the Corporation's issued and outstanding common shares. Accordingly, the Province has the power to determine the composition of the Corporation's Board of Directors. The Corporation and the Province have a shareholder's agreement that addresses such issues as OPG's provision to the Province of the information necessary to allow the Province to periodically inform Ontario's legislature regarding matters such as: OPG's ongoing performance, compliance with market power mitigation, information in respect of matters requiring shareholder approval and appropriate financial reports. In addition, the shareholder's agreement addresses OPG's governance relationship with the Province with respect to certain actions. These include any proposal to issue or transfer shares in the Corporation or any of its subsidiaries, the preparation of long-term business plans, matters concerning dividend policy and the entering into of any major transaction by the Corporation or any of its subsidiaries which would potentially have a material effect on the financial interest of the Province or OPG's ability to make proxy tax payments. The shareholder's agreement also precludes the release by the Province of non-public, commercially sensitive information regarding OPG. In addition, the Province passed a declaration under the OBCA restricting the powers of the Board of Directors with respect to certain personnel matters and expenditures related to Pickering A, Units 1, 2 and 3.

The declaration and payment of dividends are at the sole discretion of the Corporation's Board of Directors and will be dependent upon the Corporation's results of operations, financial condition, cash requirements and other factors considered relevant by the Corporation's Board of Directors.

Conflicts of interest may arise between OPG and the Province as a result of the obligation of the Province to act in the best interests of its residents in a broad range of matters, including the regulation of Ontario's electricity industry, the regulation of environmental matters, the allocation between OPG and the Province of the costs involved in nuclear waste management, the reduction of the stranded debt from the revenues of the electricity industry and any future sale by the Province of all or any of the Corporation's assets or common shares and the determination of the amount of payments to be made by the Corporation to the Province by way of dividends. For example, in 2002 the Province enacted the *Electricity Pricing, Conservation and Supply Act, 2002*. See "– *Background – Evolution of Ontario's Competitive Electricity Market*".

The Province has the power to alter the proxy tax, the gross revenue charge or other taxes or similar charges imposed on OPG.

Under the current taxation regime, the Corporation and its subsidiaries could incur material tax liabilities, or lose the right to deduct certain material amounts in respect of contributions to the segregated funds established in respect of nuclear waste management and decommissioning liabilities in calculating income subject to proxy tax or income tax, as the case may be, if the Province's equity interest were to fall below the 90% threshold. See "– *Relationship with the Province and Others – Stranded Debt and Proxy Taxes*".

Under the Ontario Nuclear Funds Agreement, any changes to OPG's reference plans or cost estimates for nuclear waste management and decommissioning, other than changes required by a regulatory authority, require the approval of the Province, acting reasonably. There can be no assurance as to the terms on which any such approval might be granted or that the Province will accept any reference plan cost estimates that result in a reduction in payments under the Ontario Nuclear Funds Agreement.

Effects of Ontario Economy

An economic slowdown in Ontario would negatively impact OPG's earnings. During the period beginning in the 1950s and ending in the 1980s, the annual growth rate of electricity demand in Ontario declined from approximately 8% to approximately 3% on a weather-normalized basis, a pattern which was typical across North America. In the early 1990s, consumption in Ontario declined both as a result of the recession and due to the substantial electricity price increases in Ontario which were required, in large part, to recover capital costs associated with construction of the Darlington nuclear generating station. Price increases for electricity also precipitated substantial fuel switching from electricity to natural gas. Between 1994 and 2002 overall electricity demand grew at an annual rate of about 1.5% on a weather normalized basis, but in 2003 it remained flat as a result of slow economic growth, SARS and the August Blackout. OPG expects Ontario primary demand to grow at an average annual rate of 1.4%, on a weather-normalized basis, between 2004 and 2010.

Forward-Looking Information

This annual information form includes forward-looking statements and information. Words such as "may", "will", "expect", "anticipate", "believe", "estimate", "plan", "intend" and similar expressions have been used in this annual information form to identify forward-looking statements. These forward-looking statements have been based on estimates and assumptions made by OPG's management. Although OPG believes that these estimates and assumptions are reasonable, actual results could differ materially from those projected in the forward-looking statements. Forward-looking statements are not guarantees of future performance or results and are subject to various factors, including the risk factors contained herein. OPG is not obligated to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. Because of these risks, uncertainties and assumptions, undue reliance should not be placed on these forward-looking statements.

ITEM 4 - SELECTED CONSOLIDATED FINANCIAL INFORMATION

Selected Historical Financial Information

(millions of dollars except per share data)

Revenue and Net Earnings for the year ended December 31	2003	2002 Restated	2001 Restated
Revenue[1]	5,178	5,746	6,239
Fuel and other expenses before below noted items	5,010	5,472	5,769
	168	274	470
Restructuring	0	222	67
Impairment of long-lived assets	576	0	0
Other income, expense and income taxes	83	(15)	(214)
Net income	(491)	67	189
Basic and diluted earnings per common share	(1.92)	0.26	0.74
Dividends per common share	0.07	0.52	1.46

Financial Position as at December 31	2003	2002 Restated	2001 Restated
Total assets	19,451	20,137	19,267
Long-term liabilities	12,983	12,644	11,990
Shareholder's equity	4,979	5,487	5,554

[1] Net of Market Power Mitigation Agreement rebate

Share Capital and Sole Shareholder

The authorized share capital of the Corporation consists of an unlimited number of common shares. As at December 31, 2003, 256,300,010 common shares are issued and outstanding, all of which are owned directly by the Province. Holders of common shares are entitled to one vote per share at meetings of the shareholders of the Corporation and to receive dividends if, as and when declared by the Board of Directors of the Corporation. Holders of common shares would participate, *pro rata* to their holding of common shares, in any distribution of the assets of the Corporation upon its liquidation, dissolution or winding up. See "*Business of OPG – Relationship with the Province and Others – Relationship with the Province – Shareholder Agreement and Dividend Policy*" for a description of the Corporation's dividend policy. No options to purchase securities of the Corporation or of any of its subsidiaries are currently outstanding.

ITEM 5 - MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The information which appears under the heading "Management's Discussion and Analysis" in the 2003 financial statements of the Corporation is incorporated herein by reference.

ITEM 6 - MARKET FOR SECURITIES

As at March 31, 2004, none of the Corporation's securities are listed and posted for trading or quoted on any exchange or quotation system.

ITEM 7 - DIRECTORS AND OFFICERS

Directors and Senior Management

The following table sets forth the name, municipality of residence, position with the Corporation and principal occupation of each of the directors and members of senior management[(1)] of the Corporation as of March 31, 2004.

Name and Municipality of Residence	Position with the Corporation and Period of Service on Board	Principal Occupation
JAKE EPP[1] Calgary, Alberta	Director and Chairman of the Board of Directors since December 2003	Chairman of the Board of Directors
KATHRYN A. BOUEY[1] Toronto, Ontario	Director since December 2003	Secretary of Management Board of Cabinet; Deputy Minister of Management Board Secretariat and Chair of the Civil Service Commission for the Government of Ontario
JAMES F. HANKINSON[1] Toronto, Ontario	Director since December 2003	Corporate Director
C. IAN ROSS[1] Toronto, Ontario	Director since December 2003	Chairman, Growthworks WV Canadian Fund Inc.
RICHARD DICERNI .... Mississauga, Ontario	Acting President and Chief Executive Officer since December 2003	Acting President and Chief Executive Officer since December 2003
DAVID W. DRINKWATER .... Toronto, Ontario	Executive Vice President and Chief Financial Officer	Executive Vice President and Chief Financial Officer
JOHN D. MURPHY .... Pickering, Ontario	Executive Vice President – Human Resources and Chief Ethics Officer	Executive Vice President – Human Resources and Chief Ethics Officer
PIERRE CHARLEBOIS .... Pickering, Ontario	Acting Chief Nuclear Officer	Acting Chief Nuclear Officer
BRUCE BOLAND .... Toronto, Ontario	Senior Vice President – OPG Customer Solutions	Senior Vice President – Customer Solutions
JAMES (JIM) PATRICK TWOMEY...... Toronto, Ontario	Senior Vice President – Electricity Production	Senior Vice President – Electricity Production

Name and Municipality of Residence	Position with the Corporation and Period of Service on Board	Principal Occupation
JAMES (JIM) BURPEE Toronto, Ontario	Senior Vice President – Trading & Portfolio Management	Senior Vice President – Trading & Portfolio Management
PATRICK MCNEIL.......................... Whitby, Ontario	Senior Vice President – Nuclear Strategy & Support	Senior Vice President – Nuclear Strategy & Support
W.R. (BILL) ROBINSON .... Markham, Ontario	Senior Vice President – Pickering A	Senior Vice President – Pickering A
TOM MITCHELL Whitby, Ontario	Site Vice President – Pickering B	Site Vice President – Pickering B
GREGORY SMITH .... Campbellcroft, Ontario	Senior Vice President – Darlington	Senior Vice President – Darlington
GISELLE S. BRANGET..................... Toronto, Ontario	Vice President and Treasurer	Vice President and Treasurer
ADÈLE S. MALO .... Toronto, Ontario	Vice President – Law and General Counsel; Vice President – Sustainable Development; Acting Corporate Secretary	Vice President – Law and General Counsel; Vice President – Sustainable Development; Acting Corporate Secretary
BART W. DEMOSKY Mississauga, Ontario	Chief Risk Officer	Chief Risk Officer

Notes:

(1) The directors were appointed in December 2003, following the resignation of the previous members of the Board of Directors. In December, 2003, the Province, OPG's sole shareholder, announced the appointment of four members to the Board of Directors to serve in an interim capacity until a more permanent Board of Directors is appointed. The Board acts as the Audit Committee. The other Committees of the Board on (i) Human Resources and Corporate Governance (ii) Environment, Health and Safety and (iii) Nuclear Review, were suspended pursuant to the Province's announcements of December 2003. Presently, the Board as a whole is responsible for the matters that were overseen by these three Committees. On April 15, 2004, the Minister of Energy confirmed the Honourable Jake Epp as the Chairman and stated that nine further Directors were being sought.

All of the directors and senior management of the Corporation have been engaged for more than five years in their current principal occupations except as set out below:

The Honourable Jake Epp was Senior Vice President and Vice President at TransCanada PipeLines Ltd. (an energy company) from 1993 to 2000. He was also a Member of Parliament for the riding of Provencher, Manitoba from 1972 to 1993; He also held three cabinet posts: Minister of Energy, Mines and Resources (1989-1993); Minister of National Health and Welfare (1984-1989); and Minister of Indian Affairs and Northern Development (1979 – 1980).

Kathryn A. Bouey was appointed Secretary of Management Board of Cabinet, Deputy Minister of Management Board Secretariat and Chair of the Civil Service Commission in 2001. Prior to that she was Deputy Minister, Ministry of Intergovernmental Affairs from 1999 to 2001. From 1997 to 1999, she was Assistant Deputy Minister, Corporate Services Group, Ministry of Health; Ms. Bouey is lead director in the area of environment, health and safety for OPG;

James F. Hankinson was President and Chief Executive Officer of New Brunswick Power Corporation (an energy company) from 1996 to 2002; Mr. Hankinson is lead director in the area of nuclear operations for OPG;

C. Ian Ross served as Dean of Administration at the Richard Ivey School of Business at the University of Western Ontario from 1997 to September 2003; Mr. Ross is lead director in the area of finance for OPG;

Richard Dicerni was Executive Vice President and Corporate Secretary from January 2000 to December 2003. Prior to that, he was Senior Vice President, Corporate and Environmental Affairs and Corporate Secretary of the Corporation from December 1998 to December 1999. From December 1997 to November 1998, he was Senior Vice President, Corporate and Environmental Affairs, with Ontario Hydro;

David W. Drinkwater was Executive Vice President, Law and Corporate Development, from December 1998 until April 2003. Prior to that he was Special Advisor to the Chairman and Chief Executive Officer of Bell Canada (a Canadian telecommunications company) during 1998, Group Vice President, Law and General Counsel of Bell Canada from 1996 to 1998 and, before that, a senior partner of the law firm of Osler, Hoskin & Harcourt;

John D. Murphy was President of the Power Workers' Union, CUPE Local 1000 (a labour union), from 1993 to May 2000. He was appointed to OPG's Board of Directors in December 1998. Upon joining OPG as Executive Vice President - Human Resources in May 2000, he stepped down from the Board of Directors. He was appointed to the position of Chief Ethics Officer on March 5, 2002;

Bruce Boland was Senior Vice President, Energy Markets from March 2000 to August 2001, Vice President, Regulatory Affairs, of the Corporation from April 1999 to March 2000. Prior to that, he was Senior Manager of Regulatory Affairs from May 1997 to March 1999 and Manager of Pricing from October 1995 to May 1997;

Pierre Charlebois was Nuclear Chief Operating Officer and Chief Nuclear Engineer from October 2002 to December 2003. Prior to that he was Senior Vice President, Technical Services and Chief Nuclear Engineer from 1999 to October 2002 when he assumed the responsibilities of Chief Nuclear Operating Officer. He was Vice President, Station Engineering Support of the Corporation from 1998 to 1999 and was a principal of Performa International (a consulting firm) from 1996 to 1998;

James (Jim) Patrick Twomey was Chief Executive Officer at Hazelwood Power in Australia from 1996 to 2000. Prior to that Mr. Twomey was General Manager, Operations and Maintenance Development at National Power (UK) from 1994 to 1996;

James (Jim) Burpee was assigned to the Acting Chief Executive Office to assist in the management of the Financial and Operational Review of OPG from December 2003 to March 2004. Prior to that, he was seconded to Integran Technologies, where he served as Chairman and Chief Executive Officer from December 2002 until October 2003. He has also held various positions within the Corporation, including Senior Vice President, Pickering A from February 2001 until November 2002 and Senior Vice President, Electricity Production from November 1998 to February 2001;

Patrick McNeil was Vice President, Corporate Development from April 1999 to February 2002. Prior to that, he was Vice President, Corporate Planning from September 1997 to April 1999 and Vice President, Strategic and Investment Planning from April 1997 to September 1997;

W. R. (Bill) Robinson was Senior Vice President of Pickering B from February 2002 to October 2002, Site Vice President, Pickering B Nuclear Generating Station from September 1999 to February 2002. Prior to that he worked at Pickering Nuclear Generating Station as Assistant Site Vice President from February 1999 to September 1999 and Maintenance Mentor from August 1998 to September 1999. Mr. Robinson was Vice President, Harris Nuclear Plant, New Hill, North Carolina from 1993 to 1998;

Gregory Smith joined OPG in July 2002. Prior to joining OPG, he worked for 10 years at Energy Northwest, where he held several positions including Operations Manager, Plant General Manager and Vice President, Generating Resources;

Tom Mitchell was Vice President, Nuclear Operations from April 2002 until February 2003. Prior to that he was Vice President, Assistance at the Institute of Nuclear Power Operations (INPO) from December 2000 to February 2003. From 1998 until December 2000, he was Vice President, International Division at INPO and served as Deputy Director at the World Association of Nuclear Operators (WANO). He also held the position of Site Vice President, Peach Bottom Atomic Power Station (Peach Bottom Township, York County, Pa.) from April 1996 until March 1998;

Giselle S. Branget was Vice President and Chief Financial Officer of Integrex, a service based subsidiary of Owens Corning Corporation (Toledo, Ohio) from May 1999 to March 2000. Prior to that, Ms. Branget was Vice President of Strategic Planning and Corporate Development of Owens Corning Corporation from March 1998 to April 1999 and served as Controller of Fibreboard Corp. (a subsidiary of Owens Corning Corporation) from September 1997 to February 1998;

Adèle S. Malo was Vice President – Legal, General Counsel and Corporate Secretary of Union Gas Limited (a natural gas storage, transportation and distribution company) from May 1998 to August 1999. Prior to that, Ms. Malo was corporate counsel to The Oshawa Group Limited (a wholesale and retail grocery distribution company); and

Bart W. Demosky was Vice President, Risk Services from January 2001 until January 2003. Prior to joining the Corporation, he worked at TransAlta Corporation in Calgary as Director, Investor Relations in 2000 and Assistant Treasurer and Director, Corporate Risk Management from 1998 to 2000. From 1996 to 1998 he was Manager, Risk Management Services at Engage Energy (a subsidiary of Westcoast Energy).

Committees of the Board of Directors

Audit Committee. The Audit Committee's mandate includes meeting with the Corporation's external auditors and reviewing the consolidated financial statements of the Corporation prior to the submission of such statements to the Board of Directors. In so doing, the Committee reviews the Corporation's financial and accounting management procedures, including the Corporation's internal accounting and financial controls and procedures, audit procedures and audit plans to ensure compliance with applicable legislative requirements and with generally accepted accounting principles. In addition, the Committee reviews matters relating to the Corporation's risk management programs and policies relating to debt and foreign exchange management. The Committee makes recommendations regarding the mandate and programs of the Corporation's internal auditor and the appointment, terms of engagement and remuneration of the external auditor.

Other Committees. The Committees of the Board on (i) Human Resources and Corporate Governance; (ii) Environment, Health and Safety; and (iii) Nuclear Review, were suspended pursuant to the Province's announcements of December 2003. Presently, the Board as a whole is responsible for the matters that were overseen by these three Committees.

Executive Compensation

The following summary compensation table sets forth the compensation paid by the Corporation for the years ended December 31 2001, 2002, and 2003 to the Chief Executive Officer and the four most highly compensated executive officers in charge of principal business units of the Corporation (the "Named Executive Officers"), as well as those individuals who would meet the *Securities Act* (Ontario) definition of "Named Executive Officer" but for the fact that they are no longer with the Corporation. The information provided in the summary compensation table differs from the information recently provided under the *Public Sector Salary Disclosure Act* (Ontario). The differences are due to the timing of payment of incentive awards. Salary disclosures under the *Public Sector Salary Disclosure Act* (Ontario) are limited to amounts listed on T4 forms for each year. Information in the summary compensation table is based on the year the incentive was earned. Incentive awards are generally earned in one year and paid early in the following year.

Summary Compensation Table

Name and Principal Position	Year	Annual Compensation Salary ($)	Bonus ($)	Other Annual Compensation ($)[1]	All Other Compensation ($)[2]	LTIP Payout ($)
Ronald W. Osborne, Former Director, President and Chief Executive Officer	2003 2002 2001	850,000 850,000 825,000	106,250 - 752,813	94,152[3] 92,811[3] 81,841	856,732 [18] 7,956 -	328,000 - 587,500[4]
Richard Dicerni, Acting President and CEO	2003 2002 2001	385,000 325,000 315,000	125,512 138,000 131,670	58,960[5] 53,755[5] 54,666	2,033 3,042 -	66,625 - 109,375[4]
Graham Brown, [(17)] Former Director and Chief Operating Officer	2003 2002 2001	800,000 750,000 676,000	562,861[20] 465,500[6] 465,710[6]	92,345[7] 88, 345[7] 51,697	1,002,112[21] 339,840[8] -	315,900 405,000 -
Pierre Charlebois, Acting Chief Nuclear Officer	2003 2002 2001	350,000 293,512 250,000	104,169 116,313 87,000	67,070[9] 56,398 55,909	3,146 12,706 -	59,935 - 72,583[4]
David Drinkwater, Executive Vice President and Chief Financial Officer	2003 2002 2001	454,167 412,000 400,000	149,513 294,000[10] 309,000[10]	90,126[11] 89,808[11] 52,628	1,199 1,285 45,000[12]	82,301 - 135,625[4]
John Murphy, Executive Vice President Human Resources and Chief Ethics Officer	2003 2002 2001	321,000 312,000 300,000	97,411 112,320 112,800	60,846[13] 56,943[13] 58,545	2,838 3,216 -	60,645 - -
James Twomey, Senior Vice President Electricity Production	2003 2002 2001	312,500 253,333 93,353	294,566[14] 200,891[14] 60,108[14]	112,788[15] 106,619[15] 45,979	2,956 2,062 -	- - -
Snick Meyers, [(17)] Former Senior Vice President Trading & Portfolio Management	2003 2002 2001	611,999 657,779 256,248	TBD[19] 556,079 248,797	70,075[16] 73,522[16] 27,837	1,436[19] 1,836 -	TBD[19] - -

Notes:

(1) Includes taxable car or housing allowances, flexible benefits payments, life insurance for 2001, financial services, membership fees and professional fees.
(2) Includes life insurance for 2002 and 2003.
(3) Includes flexible benefits for 2002 of $52,811 and car allowance of $40,000 and flexible benefits for 2003 of $54,152 and car allowance of $40,000.
(4) These Long-Term Incentive Plan payments relate to the 1999-2001 period, and were paid in early 2002.
(5) Includes flexible benefits for 2002 of $23,755 and car allowance of $30,000 and flexible benefits for 2003 of $28,960 and car allowance of $30,000.
(6) Includes annual incentive bonus and project incentives paid for 2002 and 2001.
(7) For 2002 includes flexible benefits of $52,406 and car allowance of $30,000 and for 2003 includes flexible benefits of $54,032 and car allowance of $30,000 and professional fees of $8,313.
(8) Includes deferred signing bonus for 2002.
(9) For 2002, includes flexible benefits of $26,398 and car allowance of $30,000, and for 2003 includes flexible benefits of $37,070 and car allowance of $30,000.
(10) Includes project incentives for 2002 and 2001.
(11) For 2002 includes flexible benefits of $31,025, car allowance of $30,000 and membership fees of $28,783 and for 2003 includes flexible benefits of $32,542, car allowance of $30,000 and membership fees of $27,584.
(12) Includes guaranteed transitional award payments per employment contracts.
(13) For 2002 includes flexible benefits of $26,943 and car allowance of $30,000 and for 2003 includes flexible benefits of $30,846 and car allowance of $30,000.
(14) Includes annual incentive bonus and special incentives.
(15) For 2002 includes flexible benefits of $16,619 and car allowance of $30,000 and housing allowance of $60,000. For 2003 includes flexible benefits of $22,788.08 and car allowance of $30,000 and housing allowance of $60,000.
(16) For 2002 includes flexible benefits of $43,552 and car allowance of $30,000 and for 2003 includes flexible benefits of $39,068 and car allowance of $24,000 and professional fees of $7,007.
(17) These individuals would have met the *Securities Act* (Ontario) definition of "Named Executive Officer" but for the fact that they are no longer with the Corporation.
(18) Includes retiring allowance of $850,000, paid in 2004.

(19) The retiring allowance, annual incentive bonus and Long-Term Incentive Plan payments are still to be determined ("TBD"), as they have not yet been agreed to by all stakeholders.
(20) Includes annual incentive bonus and project incentives.
(21) Includes lump sum payment on termination of employment.

Annual Incentive Plan

Effective January 1, 1999, the Board of Directors approved the establishment of an Annual Incentive Plan ("AIP") for management group employees. The plan was designed to incent and reward management for achieving key annual financial and operational objectives that support and help achieve short and long term business strategies.

Each year the Human Resources Corporate Governance Committee established Corporate performance goals and measures at threshold, target and stretch levels. Funds available for distribution to the management group were based on achieving Corporate performance above threshold. Bonus payments under the plan were based on achieving measured results for corporate, business unit and individual performance. Individual bonus payments were determined as a percentage of the eligible employee's base salary during the year. For the performance year 2003, all incentive awards under AIP were reduced by 20%. Bonus amounts reported for 2003 were amounts paid in 2004 with respect to fiscal 2003. For 2004, the Board has capped the amount available for the AIP at $21 million, and the percentage of eligible employee base salary for individual bonus payments has also been reduced.

Long-Term Incentive Plan

The Board of Directors approved the establishment of a Long-Term Incentive Plan ("LTIP") for senior executives effective January 1, 1999. The objective of the LTIP was to provide an incentive to achieve outstanding performance over a longer term than the one-year period covered by annual bonus awards.

LTIP payouts were determined based on corporate results achieved during each performance period and awarded in cash. The Human Resources Corporate Governance Committee of the Board determined the performance measures and targets applicable to a given performance period at the outset of the performance period. In addition, threshold and maximum performance levels were established. LTIP payouts were not paid for performance below threshold. Threshold, target and maximum incentive awards were expressed as a percentage of the participant's average base salary over the three-year performance period.

The LTIP operated over three-year overlapping periods. Each performance period started on January 1 of the first calendar year and ended December 31 of the third calendar year. To be eligible for a payout under the LTIP, a participant must have been employed by the Corporation at the end of the three-year period. The first performance period commenced on January 1, 1999 and ended on December 31, 2001. The next period commenced January 1, 2000 and ended on December 31, 2002. The last period commenced January 1, 2001 and ended on December 31, 2003. Awards were made in 2004 for performance under the 2001 – 2003 performance period. LTIP will not continue beyond the 2001-2003 performance period and there will be no awards made under plan for the 2002 – 2004 period, nor for the 2003 – 2005 period.

Pension Plans

Messrs. Dicerni, Drinkwater, Murphy and Charlebois participate in a registered defined benefit pension plan. The plan provides a benefit at age 65 in conjunction with the Canada Pension Plan of 2% of the highest three year average pensionable earnings per year of credited service, subject to the limits imposed by the *Income Tax Act* (Canada). Pensions are paid on a joint and 66.67% survivor basis to members who have a spouse at the time of retirement. The pension is indexed to the Consumer Price Index after retirement to a maximum increase of 8% per annum. There is also a supplementary pension plan, secured by letters of credit, that provides benefits in excess of the registered plan benefits up to the level of benefits promised to each executive.

The following table shows, as of December 31, 2003, the pensions payable from the Corporation and the Corporation's pension plan at age 65 at various pensionable earnings levels and years of credited service for the above-noted participants.

Pensionable Earnings	Years of Service				
	15	20	25	30	35
$200,000	$56,963	$75,950	$94,938	$113,925	$132,913
$400,000	$116,963	$155,950	$194,938	$233,925	$272,913
$600,000	$176,963	$235,950	$294,938	$353,925	$412,913
$800,000	$236,963	$315,950	$394,938	$473,925	$552,913
$1,000,000	$296,963	$395,950	$494,938	$593,925	$692,913
$1,200,000	$356,963	$475,950	$594,938	$713,925	$832,913
$1,400,000	$416,963	$555,950	$694,938	$833,925	$972,913
$1,600,000	$476,963	$635,950	$764,938	$953,925	$1,112,913

The promised benefits and the credited service for each executive are described below.

Mr. Dicerni's credited service at December 31, 2003 is 35.22 years. This includes credited service transferred from his previous employer. For each of the first 12 years of service commencing January 1, 2000, he will receive 1.5 years of credited service for purposes of calculating his pension plan benefit. Mr. Dicerni's pensionable earnings will be comprised of his base salary and an appropriate portion of his bonus compensation paid in the year. The percentage of bonus compensation that is pensionable increases by 2% for each year Mr. Dicerni remains up to Dec. 31, 2006. Upon retirement on or after Dec. 31, 2004, Mr. Dicerni will receive a lump sum retiring allowance of $150,000. This amount increases by $50,000 if he retires on or after Dec. 31, 2005 and once again if he retires on or after Dec. 31, 2006.

Mr. Drinkwater's credited service at December 31, 2003 is 10 years. For each year of service with the Corporation until age 60, he will receive two years of credited service for purposes of calculating his pension plan benefit. Thereafter he will receive 1.5 years of credited service for each year of service. Mr. Drinkwater's pensionable earnings will be comprised of his base salary and the bonus compensation earned in the year and paid in the following year. If Mr. Drinkwater retires after the age of 55 and before age 60, his accrued pension based on service and earnings to the date of such termination, shall be payable immediately but will be reduced by 3% per annum for each year that such retirement precedes attaining the age of 60. If he retires on or after attaining the age of 60, his pension will vest immediately and will be payable without reduction. Mr. Drinkwater will receive a total pension of not less than $100,000 per annum payable from age 55. His minimum pension rises by $25,000 each year that Mr. Drinkwater remains with the Company after age 55 and up to age 60.

Mr. Twomey does not have a pension arrangement with OPG.

The remaining Named Executive Officers (Messrs. Osborne, Brown and Meyers) are no longer active employees of the Corporation.

Employment Agreements

The Corporation has employment agreements with Messrs. Dicerni, Drinkwater, Murphy, Charlebois, and Twomey. They were eligible to receive annual cash awards under the Corporation's Annual Incentive Plan based on the achievement of key corporate, business and individual performance measures. The following employment agreements contain additional terms:

- Mr. Dicerni's employment agreement provides that upon involuntary termination without cause, Mr. Dicerni would receive a period of notice of two years, either as continued payment of base salary or, at Mr. Dicerni's option and with the Corporation's consent, a lump sum payment discounted at a rate based on the average prime rate. Mr. Dicerni would be entitled to any annual or long-term incentive plan amounts that have been accrued at the commencement of the notice period and long-term disability coverage for the duration of the notice period.

- The Corporation has entered into an employment agreement with Mr. Drinkwater which guaranteed awards payable in 2001 to bridge to the long-term incentive plan. The agreement also provides for a retiring allowance in the event that Mr. Drinkwater is terminated by the Corporation without cause. The amount of the retiring allowance varies based upon Mr. Drinkwater's age and the level of his pension entitlement at the date of termination. In addition, upon termination without cause, all amounts awarded under the LTIP shall immediately vest and be paid within 90 days of the date of termination. Mr. Drinkwater may elect to terminate his employment by giving 180 days' notice if: (i) there is a fundamental change in the policies of the Province relating to the Corporation, or (ii) there is a change of control of the Corporation, other than as a result of a public offering of shares, to which Mr. Drinkwater has not consented (such consent not to be unreasonably withheld or delayed); and, as a result, there is a material change in Mr. Drinkwater's duties and/or responsibilities. In such event he will receive the same payment as if he were terminated without cause.

- The employment agreement with Mr. Twomey specifies that if the Corporation terminates his employment other than for cause, the Corporation shall pay him a lump sum amount representing his base salary for the lesser of three months or the balance of the term remaining.

The remaining Named Executive Officers (Messrs. Osborne, Brown and Meyers) are no longer active employees of the Corporation. The retiring allowances for Mr. Osborne and Mr. Brown are noted in the Executive Compensation Summary. The severance arrangements for Mr. Meyers are not yet final.

Compensation of Directors

The Corporation's Chairman, the Honourable Jake Epp, is remunerated at a level of $150,000 per annum. The by-laws of the Corporation provide that directors may receive reasonable remuneration for their services, commensurate with their duties, together with reimbursement for all reasonable expenses incurred in fulfilment of their duties, including travelling expenses. Independent external directors currently receive a $25,000 annual retainer plus $900 for each Board and committee meeting attended. In addition to other fees, the lead directors are given a $3,000 annual retainer. James F. Hankinson is the lead director in respect of nuclear operations and C. Ian Ross is the lead director in respect of finance matters. Directors who are employed by the Shareholder, the Province of Ontario or OPG management do not receive additional compensation for serving as Director. In that regard, Kathryn Bouey does not receive remuneration for her service on the Board of Directors and is also lead director for Environment, Health and Safety.

ITEM 8 - ADDITIONAL INFORMATION

Additional information, including details of directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities, options to purchase securities and interests of insiders in material transactions, where applicable, is also contained in the Corporation's annual filing of a reporting issuer, filed with the Canadian securities commissions instead of a management information circular. Additional financial information is provided in the Corporation's annual comparative financial statements for the year ended December 31, 2003. A copy of:

- this annual information form, together with any material incorporated by reference;
- the Corporation's annual filing of a reporting issuer;
- the Corporation's annual comparative financial statements for its most recently completed financial year, together with the accompanying report of the Corporation's auditor, as filed with the Canadian securities commissions; and
- the Corporation's most recent interim financial statements for a period after the end of the Corporation's most recently completed financial year, as filed with the Canadian securities commissions;

may be obtained on written request to the Ontario Power Generation Inc., 700 University Avenue, Toronto, Ontario, M5G 1X6 (Attention: Investor Relations). These documents, together with any other requested documents that are incorporated by reference in a preliminary short form prospectus or short form prospectus, will be provided free of charge while the Corporation's securities are in the course of a distribution under the preliminary short form prospectus or short form prospectus. At any other time, these documents will be provided, although payment of a reasonable charge may be required if the request is made by a person who is not a security holder of OPG. These documents are also available on OPG's website, at www.opg.com.

GLOSSARY

Organization Abbreviations

AECB	-	Atomic Energy Control Board (now the CNSC)
AECL	-	Atomic Energy of Canada Limited, a Federal Crown corporation and Canada's nuclear research and development organization, which is responsible for the design, marketing and construction of CANDU power reactors
CNSC	-	Canadian Nuclear Safety Commission (formerly the AECB)
FERC	-	Federal Energy Regulatory Commission, the independent regulatory agency with the U.S. Department of Energy that regulates the transmission and wholesale sale of electricity in interstate commerce
Hydro One	-	Hydro One Inc. and its subsidiaries
IMO	-	Independent Electricity Market Operator
Minister	-	Ontario Minister of Energy
OEB	-	Ontario Energy Board
OEFC	-	Ontario Electricity Financial Corporation

Technical and Operational Terms

"ancillary service" means a service necessary to maintain the reliability of the IMO-controlled grid;

"automatic generation control" means the process that automatically adjusts the output from a generation facility based on automated, electronic signals in order to provide frequency control and to maintain the balance between load and the output from generation facilities;

"availability", when used in reference to a generating unit, is a measure of mechanical reliability represented by the percentage of time a generating unit is capable of providing service, whether or not it is actually in-service, relative to the total time for the period;

"base load capacity" is generating capacity used to serve an essentially constant level of customer demand; typically, base load units operate whenever they are available and have capacity factors greater than 60%;

"bilateral contract" is a contract for the purchase and sale of notional electricity usually entered into directly between a generator and an end-user or between a generator or end-user and a market intermediary;

"black start capability" means the demonstrated potential for a generation facility (as established by tests in accordance with the provisions of an ancillary service contract) to start without electrical system supply; it is the intention of the IMO to use the energy of such a generation facility to energize a defined portion of the IMO-controlled grid;

"broker" and **"marketer"** each refer to a profit-motivated entity that acts as an intermediary in arranging transactions between or on behalf of generators and customers. It may assemble load or generation into larger blocks (an aggregator), act as a negotiator between buyers and sellers (a broker), or buy, sell and take physical positions in the marketplace (a marketer);

"CANDU" is an acronym for Canadian Deuterium Uranium, a family of nuclear fission reactors developed in Canada which use pressurized heavy water coolant or deuterium as a moderating agent and natural uranium (uranium dioxide) as fuel;

"capability factor" is the amount of energy capable of being produced by a generating unit as a percentage of its maximum output assuming no external constraints such as transmission limitations;

"capacity factor" is an operational statistic which is determined for a period of time, usually one year. The capacity factor of a generating asset is usually specified as a percentage and is defined as the ratio of the amount of energy that the asset actually generated over a period of time; divided by the amount of energy that the asset would have produced over the same period of time if it had operated continuously at full capacity. Capacity factors depend on whether a facility is used for continuous, intermittent or occasional operation, related operational decisions, such as planned outages and weather. The average capacity factor for a portfolio of generating units may vary from these values due to the number of units in the portfolio and the operating characteristics of those units;

"capacity reserve" means generation capacity that would be bid into a real-time market to address concerns about low reserve margins, the security of the electricity system and the adequacy of the electricity system to meet the demand for energy;

"certified black start facility" means a registered facility that, to the satisfaction of the IMO acting reasonably, has complied with and continues to comply with equipment and staffing configurations, training and maintenance programs and inspection and testing regime as set out in the Market Rules or the Ontario power system restoration plan, and from which the IMO may direct the delivery of power without assistance from the electrical system;

"decommissioning" refers to those actions taken in the interest of health, safety, security and protection of the environment to retire a nuclear facility permanently from service and render it to a predetermined end-state (final or interim) condition;

"decontrol" means the mandated transfer of effective control in respect of output, being control over the timing, quantity and bidding into the Ontario market of such output;

"demand-side bidding" means an agreement between the IMO and an electricity user to reduce the user's consumption (load) of electricity by agreed amounts under specified circumstances;

"forced outage" means the removal from service availability of a generating unit, transmission line, or other facility for emergency reasons or unanticipated failure;

"Gg" means a gigagram, or one billion grams;

"head" means the difference between water levels at the intake and outflow of a hydroelectric generating station;

"IMO-administered markets" means the markets established by the Market Rules;

"IMO-controlled grid" means the transmission systems in Ontario which are under the direction of the IMO;

"interconnection" means a transmission line which carries power across the service area boundary of geographically adjacent jurisdictions;

"installed capacity" is the highest level of output which a generating unit is designed to maintain indefinitely without damage to the unit;

"in-service capacity" is that portion of installed capacity that has not been removed from service;

"**intermediate capacity**" is generating capacity intended to operate fewer hours per year than base load capacity but more than peaking capacity; typically, intermediate capacity units have capacity factors ranging from 30% to 60%;

"kilo" is a prefix meaning one thousand; a kilowatt (kW) is 1,000 watts;

"kWh" means a kilowatt hour and is the commercial unit of electric energy. A kWh is the amount of electricity consumed by ten 100W light bulbs burning for one hour;

"load" means the quantity of electricity consumption measured as either the energy consumed over a given period of time or the rate of energy consumption at a given time by a particular customer or group of customers;

“market power mitigation” is a framework composed of a combination of a price cap and rebate mechanism and decontrol of capacity obligations that was approved by the Province in order to protect the interests of consumers while ensuring an orderly and gradual transition to a long-run industry structure in which OPG’s generating capacity available to the Ontario market is substantially reduced;

“Market Rules” are rules made and enforced by the IMO that govern the IMO-controlled grid and that establish and govern the IMO-administered markets relating to electricity and ancillary services;

“mega” is a prefix meaning one million; a megawatt (MW) is 1,000,000 watts or 1,000 kW;

“must-run contracts” are contracts between the IMO and a generator which allow the IMO to call on a generator’s facility, at times when the facility may not otherwise be available for production, in order to maintain the reliability of the electrical system;

“MWh” means a megawatt-hour and is equal to 1,000 kWh;

“Market Opening” is the introduction of competition in Ontario to supply electricity in both the wholesale and retail markets through the opening of access to Ontario’s transmission and distribution systems which occurred on May 1, 2002;

“operating reserve” means the capacity that can be called upon on short notice by the IMO to replace scheduled energy supply that is unavailable as a result of an unexpected outage or to augment scheduled energy as a result of unexpected demand or other contingencies;

“peaking capacity” means generating capacity intended to be operated intermittently to provide power during maximum load peaks; typically, peaking capacity units have capacity factors of less than 20%;

“planned outage” means the removal of equipment from service availability for inspection and/or general overhaul of one or more major equipment groups. This outage usually is scheduled well in advance;

“reactive support/voltage control service” means the control and maintenance of prescribed voltages on the IMO-controlled grid;

“Standard Supply Service” means the sale of electricity in accordance with the provisions of section 29 of the *Electricity Act, 1998* (Ontario), and the OEB Standard Supply Service Code;

“stranded debt” is defined under the *Electricity Act, 1998* (Ontario) as the amount of debt and other liabilities of OEFC that, in the opinion of the Minister of Finance, cannot reasonably be serviced and retired in a competitive electricity market;

“tera” is a prefix meaning one trillion; a terawatt (TW) is 1,000,000,000,000 watts or 1,000,000,000 kW or 1,000,000 MW;

“Tg” means a teragram, or one trillion grams;

“tonne” means 1,000 kilograms or 2,204.6 pounds;

“TWh” means a terawatt hour and is equal to 1,000,000 MWh;

“unit” means an electrical generator, together with its driving turbine and auxiliary equipment;

“W” or **“watt”** is a scientific unit of electric power representing the rate of work of one joule per second; and

“weather-normalized” means an adjustment to demand statistics in a market to account for the deviation of weather from normal weather conditions in that market.