ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2001

ONTARIO POWER GENERATION INC.

April 30, 2002

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All references to dollars in this annual information form are to Canadian dollars. In this annual information form, "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 technical and other terms relating to the electricity industry. See "Glossary" for the definitions or explanations of these terms.

ITEM 1 - CORPORATE STRUCTURE

Ontario Power Generation Inc. (the "Corporation") was incorporated under the *Business Corporations Act* (Ontario) on December 1, 1998. 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 assets, liabilities, employees, rights and obligations of the electricity generation business of Ontario Hydro (the "Acquired Business") on April 1, 1999.

OPG is one of the largest electricity generators in North America. OPG's principal business is the generation and sale of electricity. This electricity is acquired by wholesale electricity customers in Ontario, including local distribution companies that sell electricity to their retail customers, and directly by large industrial consumers, with additional electricity being marketed and sold into the interconnected markets of other provinces and the U.S. northeast and midwest. In 2001, OPG generated 121.6 TWh of electricity in Ontario and purchased 19.1 TWh of electricity for resale. Of this total, 136.6 TWh were used to meet demand in Ontario, 3.6 TWh were sold to the interconnected markets and the remainder of 0.5 TWh was delivered to neighbouring jurisdictions pursuant to special arrangements.

As of December 31, 2001, OPG's electricity generation portfolio, with a total net in-service capacity of 22,657 MW, consisted of: three nuclear stations, six fossil fuelled generating stations; 40 hydroelectric generating stations; and a green energy portfolio of 29 small hydro and two wind generating stations. In addition, OPG's Pickering A Nuclear Generating Station, with a net in-service capacity of 2,060 MW, was temporarily laid up and the Bruce A and B Nuclear Generating Stations were leased on a long-term basis to Bruce Power L.P. ("Bruce Power"). OPG's stations offer dispatch flexibility of base load, intermediate and peak capacity and are diversified by fuel type and technology. OPG is a low-cost generator in its regional market area, particularly in relation to the U.S. northeast and midwest.

OPG's electricity generation assets are held through subsidiaries of the Corporation and are leased back to and operated by the Corporation. These subsidiaries are generally organized by operating group (hydroelectric, fossil, nuclear and corporate) based on the location of the facilities owned by each subsidiary, as follows:

Hydroelectric Generation Subsidiaries, grouped by the river systems on which OPG's hydroelectric stations are situated, are OPG-Abitibi River Inc., OPG-Madawaska River Inc., OPG-Mattagami River System Inc., OPG-Northwest Plant Group Inc., OPG-Ottawa River Inc., OPG-Small Hydro Inc., OPG-Mississagi River Inc., OPG-Montreal River Inc., OPG-Niagara Plant Group Inc. and OPG-St. Lawrence River Inc.;

Fossil Generation Subsidiaries, grouped by station, are OPG-Atikokan Inc., OPG-Lakeview Inc., OPG-Lambton Inc., OPG-Lennox Inc., OPG-Nanticoke Inc. and OPG-Thunder Bay Inc.; and

Nuclear Generation Subsidiaries, grouped by station, are OPG-Huron A Inc., OPG-Huron B Inc., OPG Waste Inc., OPG-Huron Common Facilities Inc., OPG-Pickering Inc., OPG-Pickering Waste Inc., OPG-Darlington Inc. and OPG-Darlington Waste Inc.

Furthermore, OPG-700 University Inc. holds and leases back the property where OPG's head office is located. The Corporation also has subsidiaries that have been incorporated for specific purposes. These subsidiaries include Ontario Power Inc., Ontario Power Interconnected Markets Inc., OPG EBT Holdco Inc., Ontario Power Generation Energy Trading, Inc. and OPG Ventures Inc.. Ontario Power Generation Energy Trading, Inc. holds all of the issued and outstanding shares in the capital of Ontario Energy Trading, Inc., which in turn holds all of the issued and outstanding shares of Ontario Energy Trading International Corp.

Each of the foregoing corporations is wholly-owned by the Corporation and incorporated under the *Business Corporations Act* (Ontario), with the exception of Ontario Power Interconnected Markets Inc., Ontario Energy Trading, Inc. and Ontario Energy Trading International Corp. which are incorporated pursuant to the *Delaware General Corporation Law.*

OPG also holds an approximate 49% interest in Integran Technologies Inc., an engineering services company, a 50% interest in Brighton Beach Power Ltd. (a general partner), a 49.95% interest in Brighton Beach Power L.P. (a limited partnership), a 50% interest in Huron Wind Inc. (a general partner) and a 50% interest in Huron Wind L.P. (a limited partnership). Each of the foregoing entities was incorporated or formed under the *Business Corporations Act* (Ontario) or the *Limited Partnerships Act* (Ontario), as applicable.

The information contained in this annual information form concerning OPG or the Corporation for periods prior to April 1, 1999 relates to the electricity generation business that was previously owned and operated by Ontario Hydro and is now owned and operated by OPG, unless the context indicates otherwise. In May 2001, OPG completed the agreement to lease its Bruce A and Bruce B generating stations with Bruce Power L.P. The information contained in this annual information form applicable to periods since commencement of the Bruce Power lease does not include these stations, unless specifically noted to the contrary. In addition, unless specifically noted to the contrary, the information contained in this annual information form includes OPG's four hydroelectric stations on the Mississagi River system, which the Corporation expects to sell in the second quarter of 2002.

ITEM 2 - BACKGROUND

Overview

The electricity industry is principally made up of four components: generation, transmission, distribution and marketing of energy and other 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. The electricity OPG generates is sold into an hourly physical market administered by the IMO. In addition, OPG enters into various financial-based energy market transactions with large volume end-use customers and intermediaries such as utilities, brokers, aggregators, traders and other power marketers and retailers. Energy marketing in deregulated markets includes spot market sales and trading, the sale of bilateral risk management products and sales of energy-related products and services to meet customers' needs for energy solutions. OPG's products and services currently include various financial-based energy products as well as value-added billing, reporting and verification services, evergreen power products, utility monitoring and management services and ancillary, or reliability-related, services sold to the IMO.

Electricity has traditionally been generated in large multi-unit centralized 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 (being whether the electricity generated by a particular generating station is dispatched to meet peak, intermediate or base load demand). Capacity is typically expressed in MW; the energy produced by a station is generally expressed as a function of the time during which the station operates, in terms of megawatt hours ("MWh").

When determining what type of generation station should be built, various factors are considered including: the total cost of the facility; the availability and cost of fuel, from both a short-term and long-term perspective; the development and operating costs of the facility; the duration of the construction period; the future price of electricity; accessibility to the high voltage transmission system; and the facility's expected life span. The emissions characteristics and other environmental impacts of the different types of generating stations and their fuel have become an increasingly important consideration. In recent years, the fuel of choice for the majority of new power project developments has been natural gas due to its availability and relatively low emission characteristics and to technological improvements leading to lower capital and operating costs. However, with fuel price volatility expected to continue and the advancement of emission control technologies, the building of several coal generating facilities outside Ontario have recently been announced.

Historically, very large generating stations were constructed to realize economies of scale, notwithstanding greater risks associated with the significant initial capital costs of such stations. However, generation technologies have progressed to the point where, depending on the circumstances - in particular the cost of fuel and the selling price of electricity - smaller generating stations may be better able to compete with larger centralized facilities. The construction of these smaller stations also tends to reduce construction time and project complexity, and therefore financial risk.

Generating stations are called upon to produce energy 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 energy 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 required to meet the demand in the area served by the electrical system.

Factors determining the overall demand for electricity in a particular area include: weather conditions; the level of economic activity; the energy requirements of individual sectors of the economy; the extent to which these requirements are met by electricity rather than other energy sources; and technical progress in the efficient use of electricity. Consequently, demand for electricity varies by season (temperature differences), day of the week (mainly influenced by the level of commercial and industrial activity) and time of day (business and residential use increase during the day and decrease during the night).

Electricity is an essential commodity that cannot be easily or economically stored in large volumes. Generation of electricity must 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 regulated regional system operators. Electricity systems have evolved on a regional basis and in general are 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 have built generating, transmission and distribution facilities to serve the needs of the customers 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 has been 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, customers had no choice of supplier, and suppliers were not free to pursue customers outside their designated service territories.

In some jurisdictions, including the United States and parts of Canada, programs were established as early as the 1970s to encourage the development of generation capacity by independent, or non-utility, generators. These generators typically entered into long-term contracts with host utilities to sell power at prices reflecting the utility's avoided cost related to the supply of electricity.

Restructuring in the Electricity Industry

In recent years, a number of jurisdictions, including the United Kingdom, continental Europe, Australia, New Zealand, parts of South America and parts of North America, have embarked on or completed a process of restructuring their electricity industries by moving away from vertically integrated monopolies and towards more competitive market models. This shift typically has involved the removal or relaxation of legislative and regulatory barriers for new generation entrants and has often been made in conjunction with other measures to stimulate competition, add sources of supply and increase access to the transmission system.

There are a number of elements common to these restructurings. First, in endorsing industry restructurings, governments, regulators and industry participants have generally concluded that the generation of electricity and the provision of energy services to end-users are not natural monopolies. Accordingly, the consensus has been that generation should be open to competition and end-users should be given the opportunity to choose their source of supply. Second, the price of energy and the addition of new capacity should be driven by market forces. Third, transmission and distribution are natural monopolies and are best managed through an independent regulator and access to transmission and distribution networks should be open on a non-discriminatory basis to generators, retailers and other purchasers of electricity. Fourth, an independent system operator should be created to maintain system reliability and security, and to ensure non-discriminatory access to these common carrier transmission systems. Fifth, an independent market operator should facilitate market-driven commercial power transactions. The roles of an independent system operator and an independent market operator could be performed separately or by a single operator.

Commercial power transactions in deregulated markets are often executed through a central power exchange (or "pool") administered by an independent market operator. Specifically, offers of energy at specified prices are made or "offered" into the power pool and sufficient generation capacity is dispatched to meet demand. Purchasers can "bid" to buy power at these "spot market" prices or, alternatively, purchasers and sellers can enter into contracts with other market participants, such as retailers and energy marketers to determine the price at which electricity will be supplied.

The distinct differences between the competitive (generation and retailing) and regulated (transmission and distribution) segments of the industry are being recognized by market participants, not only from a regulatory standpoint but also from the perspective of the differing risks and the skills and conditions required for the efficient operation of each segment. In certain jurisdictions, the market design requires functional, financial and corporate separation of these segments. This has resulted in an increase in the number of separate specialized generation, transmission and distribution companies, many of which have been created through spin-offs from previously vertically integrated utilities. Also, a number of companies which originated as independent, or non-utility, generators in the 1970s and 1980s have grown to be significant generation-focused companies. In addition, there has been a trend towards the convergence of the electricity and natural gas sectors, particularly as a significant majority of the new generation under construction in North America is expected to be fuelled by natural gas. This has resulted in an increasing number of major companies in the natural gas industry becoming significant participants in aspects of the electricity industry. Similarly, major companies in the electricity industry are becoming significant participants in aspects of the natural gas industry.

Although the elements described above have generally been followed, various jurisdictions are implementing industry restructuring in a variety of ways. The restructurings vary regarding the design of each market's rules for competition to supply energy and the rules governing the degree of access given to extra-jurisdictional suppliers. In areas where inter-regional access was previously limited, mechanisms to facilitate the development of larger markets are being established, subject to availability of physical interconnection capacity.

The implementation of electricity industry restructurings and the operation of competitive energy markets can be significantly impacted by the characteristics of each market area including demand/supply balances, the extent of transmission capacity to facilitate energy imports necessary to meet market demand, and the diversity of generation by fuel type and the related exposure to and management of fluctuations in market prices of fuel types such as natural gas. These factors all contribute to energy price volatility. In designing and planning the market structure and rules for competition in their jurisdictions, governments, regulators and other industry participants are influenced by local market characteristics and experience in other jurisdictions.

Restructuring in Ontario's Electricity Industry

Historically, Ontario Hydro had been a vertically integrated electricity utility 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 intended to cause the electricity industry to operate without government financing. Among the goals of the restructuring were creating a competitive market for electricity and facilitating the maintenance of a financially viable 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 and design of an independent market operator to manage the wholesale electricity market, to oversee the reliable operation of the integrated power system and to create the rules and protocols necessary to implement a fully competitive electricity market in Ontario. The Market Design Committee produced three quarterly reports in 1998 and a final report in January 1999. During this period, the market restructuring legislation, the *Energy Competition Act, 1998*, 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;

- Hydro One Inc. ("Hydro One"), which purchased and assumed the transmission, rural distribution and retail energy services businesses;

- the Independent Electricity Market Operator (the "IMO"), which was formed to act as both the centralized independent electricity system coordinator and independent 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
- the 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 the non-utility generator contracts in a manner compatible with the new market design.

Ontario's New Electricity Market

As a result of the opening of Ontario's electricity market to competition on May 1, 2002, there have been significant changes in the way the market operates to permit competition at the wholesale and retail levels. Generators, both from within and outside Ontario, compete to sell energy through the IMO-administered spot market. Other market participants include local distribution companies, larger industrial facilities directly connected to the transmission system, other large industrial and commercial customers who opt to be wholesale market participants, aggregators, brokers, marketers and retailers. At the retail level, end-users have the option of contracting with any licensed energy retailer. If they do not make that choice, they will continue with their current distributor under a regulated supply referred to as Standard Supply Service. See "*– The Retail Energy Market*".

All market participants have to 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 IMO-administered markets. All market participants that supply electricity into, or take electricity from, the IMO-controlled grid have to install approved interval metering at their connection points to the grid. The IMO dispatches generators based on their offers to sell energy and operating reserve. See *"Business of OPG – Regulation – Ontario's Electricity Industry – The IMO*".

In addition, the IMO and all generators, transmitters, distributors, wholesale sellers, wholesale consumers and retailers have to 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, wholesale buyer and seller, and retailer.

Consumers pay for the energy 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 "administrative charges" and "uplift charges", respectively). In addition, a debt retirement charge of $7.00 per MWh is levied to service the portion of OEFC's debt that cannot be serviced by payments made by OPG, Hydro One and the local distribution companies. See "*Business of OPG – Relationship with the Province and Others – Stranded Debt, Proxy Taxes and Effect of Change in Ownership on Tax Status".*

A regulation has been passed, however, providing transitional pricing to certain customers that had contracts with Ontario Hydro for certain specifically designated rate options. Approximately 55 large power consumers with approximately 83 sites in Ontario, whose purchases under those rate options accounted for approximately 5% of OPG's production in 2001, are eligible for this transitional price relief which is scheduled to be phased out over a period not to exceed four years after Open Access. OPG currently anticipates that its aggregate loss with respect to these contracts will be approximately $137 million.

The following section provides an overview of the roles of the principal market participants involved in the generation, sale and distribution of electricity in Ontario's new electricity market. Market intermediaries include distributors and generators when acting as wholesale sellers or retailers.

Generators

Generators function as suppliers of energy and operating reserve that is priced by the IMO-administered market. Generators may also sell ancillary products to the IMO-controlled grid, including voltage control/reactive support, black start capability and automatic generation control. Prices in the IMO-administered market will fluctuate but generators may fix the price that they receive for the sale of power by entering into bilateral contracts with third parties. See *"Background – Ontario's New Electricity Market – Other Financial Instruments".*

The IMO

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

Market Intermediaries

Market intermediaries include retailers and other aggregators, marketers and brokers of energy. Market intermediaries, if properly licensed and authorized, may purchase energy at the spot market price from the IMO and resell such energy to Ontario end-users, usually at a fixed price. Distributors, including municipal electricity utilities and other local distribution companies, distribute electricity from the IMO-controlled grid to end-user customers in local regions. Distributors acquire their electricity from the spot market or from market intermediaries under terms approved by the OEB to meet their obligations to provide regulated supply to customers who do not choose an alternative energy supplier. Wholesale sellers may provide financial or risk management products to facilitate such things as price-volatility protection and may purchase energy on a spot basis out of the pool for subsequent resale into interconnected markets at either prevailing spot prices in those markets or to other non-Ontario end-users. Retailers are another group of spot energy purchasers that may purchase energy from the IMO or wholesale sellers, and package and resell that energy to end-users.

Ontario End-Users

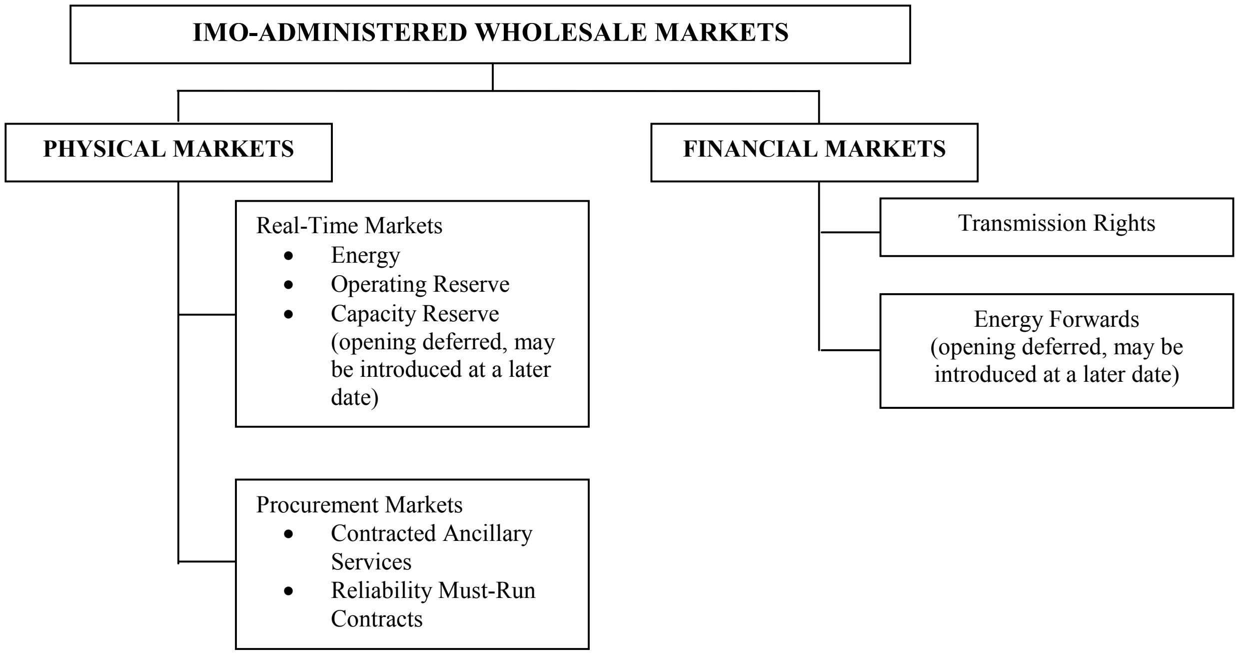
Ontario end-users include industrial, commercial and residential customers. Large end-users, if they are directly connected to the IMO-controlled grid (called "wholesale consumers"), have the option of purchasing energy directly from the IMO-administered market or from a market intermediary. Other end-users are generally expected to purchase from a market intermediary.

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 energy into the interconnected markets are required to purchase the energy out of the IMO-administered spot market for resale into the interconnected markets.

The IMO-Administered Wholesale Markets

The IMO-administered wholesale market for energy services consists of both physical markets, relating to the dispatch and pricing of energy and ancillary services, and financial markets, which are focused on financial risk management associated with the exposure to spot market energy prices and to transmission constraints by market participants. 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 Physical Markets

The IMO-administered physical energy markets consist of both real-time and procurement markets: real-time markets for energy and operating reserve and, if implemented, capacity reserve, and procurement markets for additional generation-related services to maintain reliability of the transmission grid.

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 to, for example, replace scheduled energy 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 at established 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 energy at specified prices for each hour of a given day (the “dispatch day”) are made by generators in Ontario and elsewhere. Intermittent generators may designate their facility as “non-dispatchable”, in which event they receive the market clearing price for all electricity generated by their 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. If such consumer does not follow the IMO dispatch instructions, it generally will be in breach of the Market Rules. 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.

The energy market 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 an increase in 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, again, based on metered quantities.

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

The IMO is considering the establishment of a real-time capacity reserve market which is a mechanism to provide reserves on an ongoing basis, in order to improve the security of the electricity system and the adequacy of the electricity system to meet the demand for energy. Generators would participate in this market by offering to make generating capacity available, receiving a clearing price for this capacity in addition to the market-clearing price for any energy supplied.

Procurement Markets

The IMO maintains the reliability of the transmission grid through ancillary services (operating reserve, voltage control/reactive support, black start capability and automatic generation control) and must-run contracts for local reliability. Ancillary services other than operating reserve are purchased through procurement markets. Must-run contracts for reliability 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 costs of providing these services are charged by the service provider to the IMO, which passes the expense to consumers through uplift charges.

The IMO arranges suppliers for these services either through a competitive tendering process or through contracts, 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.

The IMO Financial Markets

The IMO-administered financial markets are intended to provide market participants, such as purchasers of electricity, wholesale market participants, generators and aggregators, 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 against the possibility that they will bid to purchase electricity from or offer to sell electricity to, the IMO at an inter-tie, 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 markets at that inter-tie. When the flows of power are such that an inter-tie reaches its capacity, it is usually a reflection of, or results in, significant variations in energy prices on either side of the inter-tie. Through the transmission rights market, importers or exporters of energy are provided a financial hedge for the congestion impact on the price of power across constrained interconnections. 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.

The opening of an IMO energy forward market has been deferred for at least 12 months following Open Access. The IMO energy forward market is designed to operate one day ahead of the actual physical market day, allowing participants to hedge offers or bids for specified quantities of energy for each hour of the next day based on the clearing price in the forward market.

Other Financial Instruments

Market participants may choose to sell financial risk management products to intermediaries or customers within or outside of Ontario that are designed to reduce exposure to volatility in spot market prices. These contracts, sometimes referred to as derivatives, bilateral contracts or contracts for differences, do not involve the physical delivery of energy. They are, however, of interest to generators and consumers of energy, as they have the effect of fixing the price at which such parties sell and purchase energy. For example, generators in the new market sell energy at the spot market price. To protect against the risk of spot market price decline, a generator may agree with a counterparty that, on a given date in the future, they will exchange a payment equal to the difference between the actual spot market price for the period covered by the contract and a fixed price agreed to by them at the time they enter into the contract. This contract, when entered into between a generator and a consumer of energy, has the effect of fixing in advance the price at which they sell and purchase energy in the future. See "*Business of OPG – Markets and Customers – Commercial Strategy*".

In Ontario, IMO market participants have the option of settling the payments due under these contracts either directly or by using the settlement procedures established by the IMO. Non-IMO participants will settle directly with retailers and other market intermediaries.

The Retail Energy Market

Distributors are responsible for distributing energy to all end-users other than large industrial end-users directly connected to the IMO-controlled grid. In addition, there is now retail competition and end-use consumers are able to purchase energy from other market intermediaries active in the Ontario energy market.

Distributors are obliged to connect all consumers and supply those that have not elected to buy energy from a competitive retailer. The basis for pricing this service is the hourly price in the Ontario spot market. Generally, consumers with demand greater than 50 kW are charged the hourly spot price directly, while consumers with demand less than 50 kW will be charged a fixed reference price based on a forecast of the spot price and subject to terms and conditions established by the OEB. Adjustments will be calculated at the end of each year against the actual spot price, with the difference being charged or rebated over the following year. However, distributors may apply to the OEB for an exemption which would allow them to charge the spot price directly to consumers with demand less than 50 kW.

At least in the short term, the IMO-administered markets are primarily a physical market based on spot pricing. In order to hedge against the inherent risk in a spot market, some retail participants may choose to enter into contracts to hedge against the risk of price fluctuations.

Market Power Mitigation

OPG holds a large concentration of generation capacity in Ontario. In order to address the issue of the potential exercise of market power, OPG has made a commitment to comply with the "market power mitigation" measures established by its generating licence. See "*Business of OPG – Regulation – Ontario's Electricity Industry – Market Power Mitigation*".

The first main market power mitigation measure is a rebate mechanism. Currently a significant majority of OPG's energy sales in Ontario are subject to an average annual revenue cap of 3.8 cents per kWh. Any excess earned by OPG must be rebated to Ontario energy consumers via the IMO. The amount of energy sales that would be subject to the rebate mechanism from Open Access to 2004 has been predetermined on an annual basis and ranges from approximately 102 to 106 TWh, and will be reduced, with the approval of the OEB, as OPG reduces its control of generation capacity in Ontario. For example, the amount that would have been subject to the rebate mechanism for 2001 was 105 TWh (equivalent to 77% of OPG's 2001 energy sales in Ontario). This figure would have been reduced by 11.1 TWh had the market opened in May 2001, assuming that the OEB confirms that OPG's lease of the Bruce A and Bruce B generating stations constitutes decontrol. It is difficult to estimate the amount of OPG's electricity generation in 2002 that will be subject to the rebate mechanism, as it is dependent in part upon when OPG completes additional decontrol transactions and the OEB's confirmation that the Bruce transaction constitutes decontrol of generating capacity. However, it is estimated that the Bruce transaction would reduce the amount of OPG's 2002 electricity generation that would be subject to the rebate mechanism by approximately 20 TWh. At the end of each one year period following May 1, 2002, OPG will be required to pay a rebate to the IMO equal to the difference between the average spot market price, as determined by a specified formula, and a fixed price of 3.8 cents per kWh for the amount of energy sales subject to the rebate mechanism. The IMO will pass this rebate on to all energy consumers in Ontario on a *pro rata* basis. As OPG reduces its market power by decontrolling its capacity, it has the right to request that the OEB reduce the number of TWhs subject to the rebate mechanism.

The second main market power mitigation measure is a commitment by OPG to relinquish effective control over some of its generating capacity. This may be accomplished in a variety of ways, including the outright sale or lease of power stations or by entering into other arrangements, provided the result is to transfer effective control of the timing, quantity and bidding of energy produced by OPG's power stations. This measure, referred to as "decontrol", consists of two targets. The first decontrol target requires OPG to decontrol at least 4,000 MW of fossil generating capacity (1,000 MW of which can be replaced by hydroelectric generating capacity) within 42 months after Open Access. Under the current generation mix in Ontario, fossil stations tend to be the marginal generators that set the market-clearing price and thereby determine the price received by all generators offering electricity accepted for dispatch in the Ontario market. The second decontrol target requires OPG to reduce its effective control over electricity supply options (defined to include generation, inter-tie capacity and demand side bidding) to 35% or less of the total electricity supply options available in Ontario within ten years of Open Access.

In keeping with its decontrol commitments, in May 2001 OPG leased its Bruce A and B nuclear generating stations to Bruce Power L.P. This transaction has reduced OPG's generation capacity by approximately 6,236 MW, which will, if confirmed by the OEB as constituting decontrol for purposes of OPG's generating licence, help satisfy OPG's second decontrol target. As the second decontrol target will be measured up to 10 years after the market opened, OPG will assess the extent to which further decontrol initiatives are required, as it monitors its share of the total electricity supply options in Ontario as competitive generation capacity increases.

OPG has also initiated an auction process for the sale of its Lennox, Lakeview, Thunder Bay and Atikokan fossil generating facilities as well as its hydroelectric plants on the Mississagi River system. On March 8, 2002, OPG announced it had reached agreement to sell its Mississagi hydroelectric plants to Brascan Corporation for $340 million. This transaction is expected to close during the second quarter of 2002. Subject to the successful outcome of the balance of the auction process, OPG's intention is to complete the remainder of these transactions as soon as reasonably feasible. See "*Business of OPG – Generation Operations – Fossil Operations – Fossil Station Decontrol", "– Nuclear Operations – Bruce Decontrol"* and *"Business of OPG - Regulation – Ontario's Electricity Industry – Market Power Mitigation – Decontrol of Capacity*".

Whether a transaction will qualify as a "decontrol" transaction for purposes of satisfying OPG's licence requirements is not determined by the OEB until after a transaction has closed. The OEB has not yet been asked by OPG to consider whether the Bruce Power transaction and the proposed sales of Lennox, Lakeview, Thunder Bay and Atikokan fossil generating facilities and OPG's hydroelectric plants on the Mississagi River system would qualify as decontrol transactions. Although OPG believes that these transactions will satisfy its decontrol commitments, there can be no assurance that the OEB will come to that determination. The Bruce Power and Mississagi hydroelectric transactions are not conditional on, and it is expected that future transactions will also not be conditional on, OEB approval and therefore cannot be unwound even if they are determined by the OEB not to constitute decontrol transactions. Accordingly, it is possible that OPG may be required to dispose of additional generation assets in order to satisfy its 10-year market power mitigation commitments under its licence.

Expansion of Inter-Tie Capacity

To encourage the supply of energy in Ontario from the interconnected markets, Hydro One, as part of its IMO licence, is obligated to use its best efforts to expand inter-tie capacity with these markets by approximately 2,000 MW within 36 months of Open Access, subject to governmental and regulatory approvals and environmental assessments. This measure is designed to increase the physical capacity of the inter-ties. Hydro One, in conjunction with International Transmission Company, is in the process of installing phase shifting transformers which, when operational, will expand inter-tie capacity with Michigan by reducing inadvertent flows of electricity around Lake Erie. Depending on system conditions, these phase shifting transformers should increase the available transfer capability between Ontario and Michigan by up to 500 MW. Hydro One has obtained all necessary approvals from the National Capital Commission, the Ministry of the Environment and the OEB to increase the existing Ontario-Québec inter-tie transfer capacity by 1,250 MW. Hydro One and TransEnergieUS have also announced plans to construct an inter-tie of up to 975 MW which will connect Ontario with Ohio and/or Pennsylvania. Completion of this project is subject to numerous regulatory approvals and the successful conclusion of an auction of transmission rights.

ITEM 3 - BUSINESS OF OPG

Overview

OPG is one of the largest electricity generators in North America. OPG's current principal business is the generation and sale of electricity. This electricity is sold into the IMO-administered physical market for purchase by wholesale electricity customers in Ontario, including local distribution companies for resale to their retail customers, and directly to large industrial consumers. OPG also markets and sells electricity into the interconnected markets of other provinces and the U.S. northeast and midwest. In 2001, OPG purchased 19.1 TWh of electricity in addition to generating 121.6 TWh of electricity in Ontario. Of this total, 136.6 TWh were used to meet demand in Ontario and 3.6 TWh were sold to the interconnected markets and the net amount of 0.5 TWh was delivered to neighbouring jurisdictions pursuant to special arrangements.

All 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. OPG has also negotiated ancillary services contracts with the IMO. Additionally, OPG intends to capitalize on opportunities for the provision of financial risk management products to market participants and other customers in Ontario and in interconnected markets.

As of December 31, 2001, OPG's electricity generation portfolio, with a total net in-service capacity of 22,657 MW, consisted of: three nuclear stations; six fossil fuelled generating stations; 40 hydroelectric generating stations; and a green energy portfolio of 29 small hydro and two wind generating stations. In addition, OPG's Pickering A Nuclear Generating Station, with a net in-service capacity of 2,060 MW, was temporarily laid up, and the Bruce A and B Nuclear Generating Stations were leased on a long-term basis to Bruce Power L.P. OPG's stations offer dispatch flexibility of base load, intermediate and peak capacity and are diversified by fuel type and technology. OPG is a low-cost generator in its regional market area, particularly in relation to the U.S. northeast and midwest.

OPG's hydroelectric stations have a net in-service capacity of 7,369 MW which is primarily base load capacity, but which also provides intermediate and peak production, subject to water availability. OPG's fossil fleet, which is used to provide power for intermediate and peak demand, consists of 9,700 MW of net in-service capacity. These primarily coal-fired generating stations can be quickly called upon to meet variations in demand. OPG's three nuclear generating stations (excluding leased facilities) are located at two sites (one station at Darlington and two stations at Pickering), comprising a total of eight in-service reactor units (four units at Darlington and four units at Pickering B) with 5,588 MW of net in-service capacity, and four laid up nuclear units (Pickering A) with 2,060 MW of installed nuclear capacity.

Five Year Generation Summary[(1)]

	1997		1998		1999		2000		2001	
	Total (TWh)	% of Total	Total (TWh)	% of Total	Total (TWh)	% of Total	Total (TWh)	% of Total	Total (TWh)	% of Total
Hydroelectric	36.4	28	31.9	25	33.6	26	34.0	25	33.7	27.7
Fossil	24.4	18	34.2	27	36.1	27	42.4	31	40.2	33.1
Nuclear	70.3	54	59.9	48	61.4	47	59.8	44	47.7	39.2
Total	131.1	100	126.0	100	131.1	100	136.2	100	121.6	100

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

The decline in total electricity generated between 1997 and 1998 was primarily attributable to declining nuclear generation performance during that period and to the lay-up of two nuclear generating stations in 1997 and 1998 as part of a nuclear recovery plan. See *"Business of OPG – Generation Operations – Nuclear Operations – Nuclear Recovery Plan"*. In 2001, total electricity generated by OPG decreased as a result of reduced market demand and the exclusion of output generated by the leased Bruce nuclear facilities.

Market Opportunity

The power industry in Canada and the United States had an end-user market of at least US$245 billion in retail energy sales in 2000 produced by an installed base of approximately 930,000 MW of capacity. In 2000, OPG's regional markets, consisting of Ontario, the U.S. northeast and midwest, Québec and Manitoba, had an end-user market of US$109 billion in retail energy sales.

Several electricity market trends provide significant opportunity for efficient, low-cost generators and marketers of power to produce and sell energy at competitive rates and to grow through further investment in new and existing power generation assets. These trends include: increasing demand for power; the need to renew older generating plants and develop plants with environmentally cleaner, cheaper and more efficient technology; and an industry-wide restructuring that is reconfiguring the assets and ownership of traditional vertically-integrated utilities. Continued economic and population growth, combined with increasing density in urban areas and demand for heating, air conditioning and electronic infrastructure, have fuelled the demand for additional electricity generation. However, balancing supply and demand in certain markets can be particularly difficult given the long lead time to build new power stations and constraints on inter-tie capacity limiting energy imports. Imbalances between supply and demand may result in volatile prices for electricity. Generators and wholesale resellers with available energy, a reliable means of delivery, and knowledge of the interconnected electricity system can profitably participate in these markets provided they manage the significant risks referred to below.

In deregulated markets, generators and other market participants must compete with each other largely on the basis of energy price and service. Generators and purchasers of electricity in these markets must manage energy price risk. This provides opportunities to offer products to manage the risk associated with market price fluctuations.

Opportunities for the acquisition of generation assets or their output has been made possible by electricity deregulation in North America that has prompted restructuring including an accompanying divestiture of power plants by companies seeking to reconfigure their businesses.

While these developments provide significant new opportunities, they also create new challenges and risks. The ability of OPG to take advantage of the opportunities and face the challenges and risks depends on a variety of factors, including its ability to operate its generating facilities on an increasingly competitive basis, to provide the products and services its customers desire on a profitable basis and to manage the commodity price risks around its generally long electricity position. See *"Business of OPG – Risk Factors"*.

Corporate Strategy

OPG's vision is to be a premier North American energy company focused on low-cost power generation and wholesale energy sales. Its portfolio of generation assets is well-balanced and diversified in terms of technology, fuel type, market and dispatch flexibility. Its production costs are low relative to other generators in Ontario and the U.S. northeast and midwest, although not as low as those in Manitoba and Québec. OPG also has significant expertise with respect to the operation and maintenance of generating facilities. Due to its operational flexibility and expertise, OPG believes it will be able to successfully pursue opportunities presented by the restructuring of the industry and deregulation of markets.

To achieve its vision, OPG intends to leverage its strengths and direct its resources to the following objectives: the continued improvement of the efficiency and cost-competitiveness of its generation operations; the development of enhanced marketing, sales and trading expertise; the development of financial risk management products and services to take advantage of opportunities in the new competitive marketplace; and the extension of market reach by selectively expanding into its regional markets in the U.S. northeast and midwest. Whether pursued independently, through its venture capital subsidiary, OPG Ventures Inc., or using other investment platforms, OPG will also focus on building on its technology and research and development expertise to provide opportunities to invest in and exploit future energy technologies, such as fuel cells and renewable energy services. OPG management believes that this strategy will allow OPG to prepare for and capitalize on major industry changes over time.

Improve Generation Operations and Increase Cost Competitiveness

OPG's core strategy in the short term is to increase the productivity and cost competitiveness of its existing fleet of generating stations. In 1997, in conjunction with independent nuclear recovery experts, OPG developed a comprehensive nuclear recovery plan to improve the operating performance of its nuclear generating stations over a seven year period. Under the plan, OPG is continuing 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. OPG adopted a phased nuclear recovery strategy in order to focus qualified personnel and management resources on the plan's implementation. As a result, the Pickering A station was placed in short term lay-up on December 31, 1997. See – *"Business of OPG – Generation Operations – Nuclear Operations – Nuclear Recover Plan"*. This enabled OPG to focus its initial recovery efforts on the remaining eight nuclear generating units at the Darlington and Pickering B stations. The aggregate expenditures with respect to this plan as of December 31, 2001 were $1.04 billion. Expenditures related to the nuclear recovery plan during the period from 1997 to 2004 are expected to total $1.4 billion.

Another key initiative is the restart of the four laid-up units comprising 2060 MW of low cost and smog-free capacity at the Pickering A station. In 2001, the Canadian Nuclear Safety Commission ("CNSC") amended OPG's Pickering A licence to provide certain pre-restart requirements. The CNSC must be satisfied that these requirements have been met before it will authorize the restart of each unit. OPG expects to begin final commissioning of the first of the station's four units towards the end of 2002. This unit will return to service in late 2002 or early 2003, depending upon the results of commissioning and the time needed for regulatory approvals. The remaining three units are currently expected to be returned at approximately six to nine month intervals thereafter. The amended OPG licence for Pickering A is valid until June 30, 2003 (unless suspended, amended, revoked or replaced) and may be renewed.

For all of its nuclear operations, OPG's goal is to achieve top quartile performance among North American nuclear generators by 2005 based on a nuclear performance index used by the North American members of the Institute of Nuclear Power Operators and the World Association of Nuclear Operators ("WANO"). This index is designed to measure whether a nuclear generator is providing safe and reliable nuclear performance.

OPG has undertaken a program to optimize its fossil generating assets. This includes increasing the availability of fossil-fired generation by reducing airborne emissions through a program of substantial investment. The four units at Lennox have been converted from fuelling on oil alone to dual fuelling on oil and natural gas. Scrubbers were added at two of Lambton's four units in the mid-1990s and the use of low sulphur coal has increased at both Lambton and Nanticoke to reduce airborne emissions. Significant additional improvements are in progress, such as the installation of selective catalytic reduction equipment on four units, two at Lambton and two at Nanticoke, by the end of 2003. These improvements are expected to cost approximately $285 million. OPG is also pursuing a broad range of other initiatives, including operational changes, emission reduction credit trading and further developing emission control technologies. The successful implementation of these initiatives is intended to maintain the cost competitiveness of OPG's fossil operations relative to other fossil generators in its target market area and to ensure continued compliance with environmental performance standards in Ontario and in neighbouring jurisdictions.

Approximately $1 billion in capital investments and station automation efficiency improvements have been made over the past decade on several of OPG's hydroelectric facilities as part of a program to maintain and enhance the value of hydroelectric assets for the next 30 years. Over the next five years, another $400 million is to be incurred to continue this program. Since 1990, approximately 330 MW of additional capacity has been gained as a result of this program.

OPG is also pursuing initiatives to improve the cost competitiveness and operational flexibility of its business and foster a strong market orientation. In doing so, OPG believes that it is well positioned to adapt to changing conditions in the Ontario market and to pursue new or expanded business opportunities in the interconnected markets. As part of this initiative, in January 2002 OPG announced a restructuring plan that will lead to a company-wide staff reduction of approximately 17%, representing approximately 2,000 positions. OPG expects the reductions to be achieved over the next two years. In addition, a number of staff will be relocated closer to OPG's generating stations. OPG's other initiatives to date include: a renewed commitment to workforce skills development and cooperative labour relations which, combined with company-wide incentive programs, have contributed to greater operational flexibility and enhanced productivity. Within the supply chain function, OPG has achieved improved control of material and service costs through the increased use of information technology automation to support process simplification initiatives. OPG has continued the strategic outsourcing of non-core businesses and the reorganization of corporate services, internally or with partners, by concluding the information technology services outsourcing commenced on February 2, 2001 with New Horizon System Solutions and with respect to its research and development activities, the sale of its interest in Kinectrics Inc. to AEA Technology plc., effective January 1, 2002. See "*Business of OPG – Research and Development", "– Supply Chain",* and "*Information Technology*".

Develop Marketing and Sales and New Products

OPG believes that the new competitive market presents significant opportunities for cost-competitive generators, power exporters, power traders and providers of energy products and services. OPG has been developing and enhancing marketing, sales and trading capabilities, with a focus on at least four key growth areas of the new marketplace: (i) spot market energy sales and trading; (ii) the sale of bilateral financial risk management products; (iii) sales of energy-related products and services to meet customer needs for energy solutions; and (iv) sales of new value-added products and services that enhance the overall value of energy to customers in a competitive market.

As part of its strategy to take advantage of these new opportunities, OPG has opened a state-of-the-art trading floor and has invested in and implemented trading systems and other technologies to access market data and interact with other market participants and neighbouring markets. The successful implementation of this strategy is predicated on factors such as sophisticated product structuring and risk management skills to correctly price and manage complex structured products, marketplace recognition and brand equity to facilitate customer acquisition and retention, and the capability to deliver risk management products that meet customer needs. Prudent risk management systems and trading policies have been established and strict compliance is continuously monitored.

OPG has hired personnel both at the senior management and operations level with significant energy trading and marketing expertise and has trained experienced marketing and sales staff. OPG intends to build on its four decades of experience in purchasing and selling electricity in the interconnected markets and plans to continue the development of relationships with potential customers in the United States to respond to increased sales and trading opportunities in the future.

OPG is building on existing relationships with customers, its knowledge of customer needs and Ontario market dynamics to develop an expanding portfolio of products and services for new and existing customers. This portfolio currently includes various financial-based energy products as well as value-added billing, reporting and verification services to help customers manage their energy purchases, evergreen power products and Envision, a utility monitoring and management software program that helps customers reduce costs and increase control of their utility services. OPG's portfolio of energy-related products and services will continue to expand in response to customer needs for energy solutions and new opportunities for growth.

Export sales to wholesale intermediaries and large customers in the U.S. interconnected market provide an opportunity to generate significant revenue over the next five years. In recent years, OPG's abilities to take advantage of opportunities for export sales have been limited principally due to the lay-up of Bruce A and Pickering A nuclear generating facilities. Export sales reached a peak of 12.6 TWh in 1994 but averaged 3.9 TWh annually from 1997 to 2001. The planned return to service of the Pickering A units will increase energy supply in Ontario and offer additional opportunities for exports. Hydro One's obligation to expand inter-tie capacity will enhance this opportunity, as well as increase the potential for energy imports. OPG believes that it is well positioned to generate significant revenue in the U.S. interconnected markets as a result of its past experience with interconnected markets, its success in the competitive New York market, and its accumulated knowledge of the electricity system, participant cost, and pricing patterns both in Ontario and the interconnected markets. However, to take advantage of these export opportunities, OPG will need to successfully participate in the competitive process to obtain access to energy at the inter-tie zones for resale.

Extend Market Reach and Optimize the Asset Portfolio

OPG plans to achieve growth through the acquisition of selected generating assets and investment in energy technologies. OPG intends to secure generating capacity over the next several years in U.S. interconnected market areas close to Ontario in order to complement its mix of assets, strengthen sales and support energy and risk management contract obligations and pursue growth options. OPG will rely on its operating experience and performance improvements in its home market and its expertise in the sale of power into interconnected markets to optimize acquired assets to increase their production and performance. OPG intends, as part of its business strategy, to evaluate joint ventures, strategic alliances, acquisitions or other transactions in furtherance of its growth strategy. OPG believes that the implementation of its growth strategy and the optimization of its generating asset portfolio would be facilitated if it is able to meet its decontrol commitments on an accelerated basis.

New Energy Technology Opportunities

OPG's strategy is to pursue energy technology investments that will allow OPG to prepare for and exploit major industry changes over time. As has been the case in other deregulated industries such as telecommunications, emerging technologies and resulting innovations are expected to increasingly affect the competitive landscape within the energy industry. As both a longer term growth opportunity and a defensive and strategic measure, OPG is placing increased emphasis on energy technology initiatives and is assessing small-scale distributed generation development opportunities, generation-related technologies at the pre-competitive stage, and supporting venture capital financing opportunities such as technology funds. These opportunities may be pursued directly or through joint venture partnerships or alliances. For example, OPG is currently participating with other partners in the development of a solid oxide fuel cell system. OPG has established a venture capital subsidiary, OPG Ventures Inc., to invest up to $100 million in new technologies. Included in the initial investments are technologies such as fibre optic power measurement and energy management.

Markets and Customers

OPG's Markets

Ontario Market

In 2000, Ontario's population was approximately 11.7 million and Ontario's real gross domestic product ("GDP") was approximately $420 billion, reflecting an average GDP growth of growth of 4.3% per year for the five-year period from 1996 to 2000. Total generation resources within Ontario in 2001 were approximately 151 TWh. Prior to May 1, 2002, OPG was responsible for supplying (from owned and leased generation assets) most of the demand for electricity in Ontario; however, 7% of this demand was supplied by other Ontario generators operating approximately 90 non-utility generating stations (largely gas-fired cogeneration and small hydroelectric facilities) and 4% was supplied by self-generation.

During the period beginning in the 1950s and ending in the 1980s, the annual growth rate of electricity consumption in Ontario declined from approximately 8% to approximately 3% on a weather-normalized basis, a pattern that 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 2000, electricity consumption grew at an annual rate of about 1.6%, but in 2001 consumption remained unchanged from 2000 as a result of slower economic growth.

From 1990 to 2001, commercial energy consumption in Ontario (40% of total energy consumption in 2001) 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 (35% of total energy consumption in 2001) decreased from 1990 to 1993 during the period of increasing electricity rates and decreasing economic activity, but increased steadily between 1994 and 2000. However, in 2001 industrial demand decreased again due to a weak economy and declining energy consumption in Ontario's manufacturing and resource base segments. Demand in Ontario's residential sector (25% of energy consumption in 2001) 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 slightly in the last four years due to 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. The IMO currently forecasts reserve levels in June, July and toward the end of 2002 to be lower than the IMO's required planning reserve levels, while levels in May, the fall of 2002 and beyond the end of 2002 are more than adequate. The IMO notes, however, that external resources are expected to be available to offer into the Ontario market during the periods for which negative reserve margins are forecast, as during most of these periods, one or more neighbouring systems are outside their seasonal peak demand.

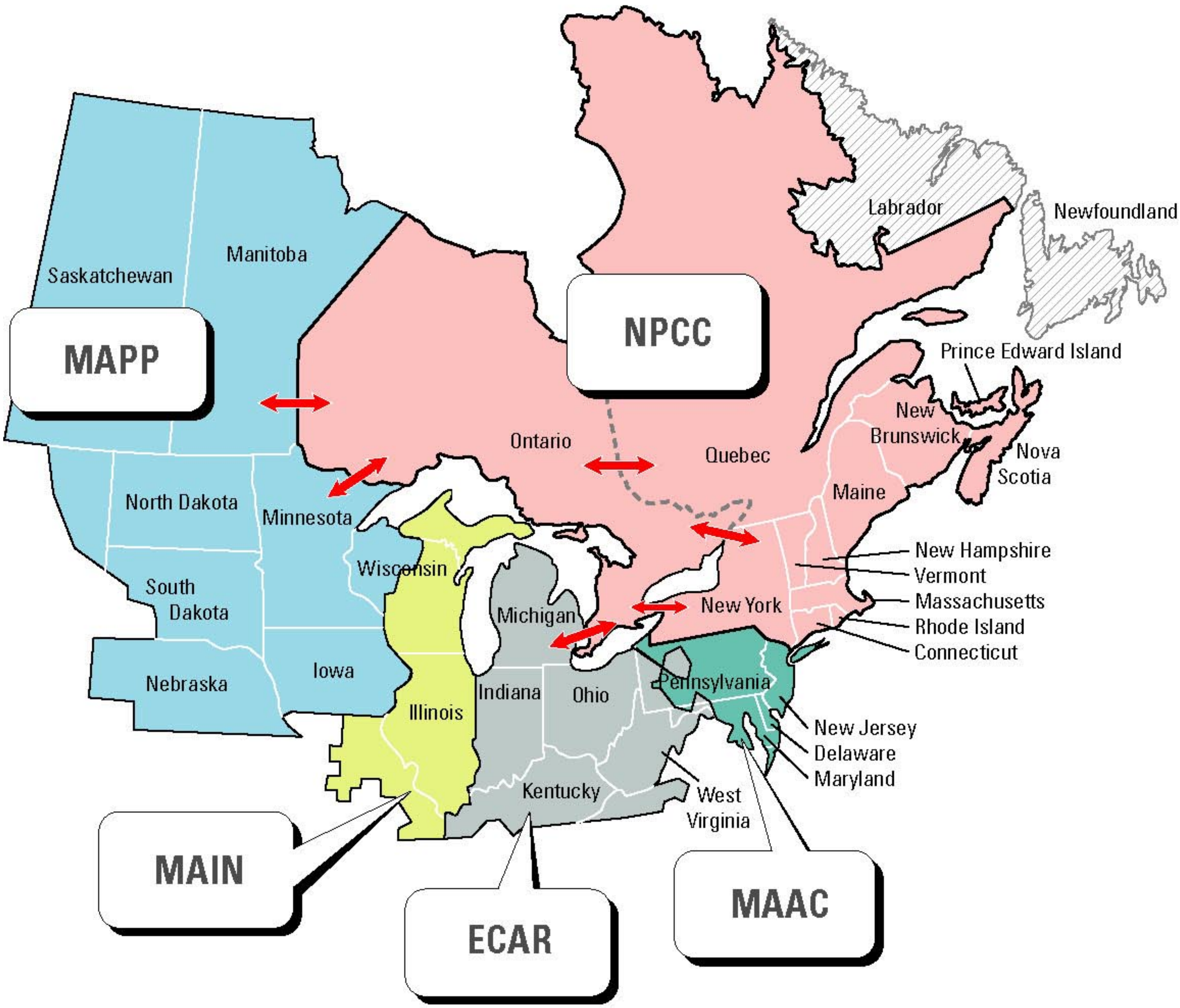
On a seasonal basis, demand for electricity peaks in the winter and in the summer. Winter peak demand usually occurs on the coldest day of the year, as a result of heating requirements. Summer peak demand usually occurs on the hottest day of the year to meet air conditioning requirements. Over the past 10 years, the increase in summer peak demand has outpaced the increase in winter peak demand. Winter and summer peak one-hour demand in Ontario are now approximately 23,000 MW on a weather normal basis. During 2001, several extremely hot weather spells resulted in new all-time highs in electricity demand in Ontario. On August 8, 2001 a record peak demand of 25,269 MW occurred in Ontario.

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 northeastern quadrant of North America. OPG has specifically targeted the interconnected markets of the U.S. northeast and midwest as a focus of its energy business. In order to maximize the opportunities in these markets, OPG has obtained the requisite market-based tariff from the U.S. Federal Energy Regulatory Commission ("FERC"). See *"Business of OPG – Regulation – Energy Regulation*

The following map depicts OPG's regional markets and notionally identifies the location of the inter-ties between Ontario and neighbouring jurisdictions. The map also shows how these markets are organized into North American Electric Reliability Council ("NERC") regions. NERC has created ten regions, covering most of North America. Reliability of the transmission systems is coordinated within each NERC region and between them. While Ontario is part of the NPCC region, regional inter-ties enable OPG to also access, directly or indirectly, four of the NERC regions and markets within them due to this network of transmission systems.

OPG's Regional Markets



NERC Regions

NPCC Northeast Power Coordinating Council

MAAC Mid-Atlantic Area Reliability Council

ECAR East Central Area Reliability Coordination Agreement

MAIN Mid-America Interconnected Network

MAPP Mid-Continent Area Power Pool

Existing Ontario Interties

Not part of NPCC

FERC is currently encouraging the formation of larger Regional Transmission Organizations ("RTOs") in the United States. An RTO is an independent manager of the transmission systems within its boundaries. RTOs are expected to provide one-stop shopping for transmission access, congestion management, and other services, which should improve the ability of market participants to transact on a regional basis. OPG's Ontario-based generation is well situated to directly access two RTOs. The Midwest Independent System Operator ("MISO"), currently the only approved RTO in the United States, has started offering transmission and other services and is working to become a fully functional RTO, including operating an energy market, over the next two to three years. The MISO service territory covers all or parts of 15 states from North Dakota to Kentucky, as well as Manitoba. Ontario is interconnected with MISO at the Michigan, Minnesota and Manitoba borders. MISO is currently in the process of merging with the Southwest Power Pool ("SPP"), a transmission organization that covers all or parts of Kansas, Oklahoma, Missouri, Arkansas, Louisiana, Texas and New Mexico. TransLink, a transmission operator covering most of Nebraska, is operating within the MISO RTO. Another group of companies, referred to as the "Alliance Companies", who own transmission in the region from Ohio to Virginia, are currently considering joining MISO or another RTO, consistent with the direction from FERC. In addition, MISO, SPP and the Pennsylvania, New Jersey and Maryland Interconnection ("PJM") have announced their intention to form a common wholesale market. PJM is a transmission organization and market operator covering all or parts of Pennsylvania, New Jersey, Maryland, Delaware and the District of Columbia and has recently taken operational control of transmission in parts of Ohio, Virginia and West Virginia (known as "PJM West"). Ontario is also interconnected at the New York border with the New York Independent System Operator ("NYISO"). NYISO and ISO-New England, the market operator covering Massachusetts, Connecticut, Rhode Island, Vermont, New Hampshire and part of Maine, have announced their intention to form a Northeast RTO.

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. The normal limits of the interconnected transmission capabilities between Ontario and the interconnected markets through inter-ties are as follows:

Ontario Inter-Tie Capabilities with Interconnected Markets

Interconnection	Limit (MW) Flows Out of Ontario	Limit (MW) Flows Into Ontario
Manitoba – Winter*	300 / 190**	369 / 259**
Manitoba – Summer*	288 / 163**	343 / 218**
Minnesota(3)	150	100
Québec North – Winter*	115(4)	78
Québec North – Summer*	107(5)	64
Québec South (East and Ottawa) – Winter*	452	1,328
Québec South (East and Ottawa) – Summer*	432	1,328
New York St. Lawrence	400	400
New York Niagara (60 Hz and 25 Hz) – Winter*(1)	2,100	1,650
New York Niagara (60 Hz and 25 Hz) – Summer*(1)	2,100	1,400
Michigan – Winter*(2)(3)	2,400 / 2,700***	1,600 / 1,750***
Michigan – Summer*(2)(3)	2,350 / 2,450***	1,500 / 1,650***

* Summer limits apply from May 1 to October 31. Winter limits apply from November 1 to April 30.

** For the Ontario – Manitoba interconnection, the displayed values are, respectively, before and after January 30, 2002 which is the expected return to service date of Whiteshell T8 transformer.

*** For the Ontario – Michigan interconnection, the displayed values are, respectively, before and after all three phase shifters are in-service and operational.

(1) Limits are based on thermal ratings and 75% of pre-load. Summer limits are based on 0-4 km/hr wind speed and 30 Deg. C ambient temperature. Winter limits are based on 0-4 km/hr wind speed and 10 Deg. C ambient temperature.

(2) Limits are based on thermal ratings and 75% of pre-load. Summer limits are based on 0-4 km/hr wind speed and 35 Deg. C ambient temperature. Winter limits are based on 0-4 km/hr wind speed and 10 Deg. C ambient temperature.

(3) For day-to-day operations of the interconnection, limits are based on ambient conditions such as wind speed, temperature and pre-loads.

(4) Limit based on 0-4 km/hr wind speed and 10 Deg. C or less ambient temperature.

(5) Limit based on 0-4 km/hr wind speed and 30 Deg. C or less ambient temperature.

In general, Ontario's inter-ties, subject to system conditions, represent an ability to import approximately 21 TWh of electricity and export approximately 30 TWh of electricity annually. Hydro One is obligated to use its best efforts to increase inter-tie capacity to neighbouring jurisdictions by approximately 2,000 MW within 36 months of Open Access, subject to governmental and regulatory approvals and environmental assessments. Collectively, these upgrades, if completed, could add approximately 12 TWh to Ontario's import/export capability, comprising 6 TWh with Québec, 4 TWh with the U.S. midwest and 2 TWh with the U.S. northeast.

Historically, OPG has 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 varies 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. In 2001, OPG sold approximately 3.7 TWh of electricity into interconnected markets, including sales to wholesale customers in these markets. As a part of its sales into interconnected markets, OPG entered into a power exchange agreement with Hydro Québec. OPG also purchased 1,462 GWh from Manitoba, 2,170 GWh from Michigan, 65 GWh from Hydro Québec and 634 GWh from New York in 2001. In most instances, purchases from neighbouring jurisdictions were traditionally made either to meet demand or in situations where it is more economic to purchase from a neighbouring jurisdiction than to produce electricity in Ontario.

OPG's Customers

Ontario Customers

In 2001, wholesale electricity customers in Ontario included approximately 90 local distribution companies, including municipal electrical utilities and privately-owned distribution utilities, that together served just under 3,000,000 customers; over 100 large direct industrial customers; and Hydro One, which served approximately 1,200,000 customers. In 2001, the local distribution companies accounted for approximately 72%, or 101.7 TWh, of total Ontario energy sales of 142.2 TWh, direct industrial customers accounted for approximately 13%, or 18.9 TWh, and Hydro One accounted for approximately 15%, or 21.6 TWh.

OPG must offer the bulk of its production into the IMO-administered real time energy market, or spot market, in order to be dispatched by the IMO. OPG also offers financial risk management products directly to end-users as well as to other wholesale parties in Ontario through bilateral contracts, and is seeking to build on its existing relationships with Ontario customers in developing these product offerings. In addition, OPG and the IMO have entered into agreements for the supply of certain contracted ancillary services by OPG, including black start capability and automatic generation control and have finalized an agreement on voltage control/reactive support.

Interconnected Market Customers

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 power on a wholesale basis for resale. 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. Prior to that, OPG sold energy at the U.S. border to the NYISO's predecessor, the New York Power Pool, and to independent entities in New York, New England and PJM (Pennsylvania, New Jersey and Maryland).

OPG has entered into enabling agreements with approximately 70 wholesale market participants in the U.S. northeast and midwest regarding the purchase and sale of energy. OPG, through its U.S. subsidiary, has recently 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 increases OPG's access to the U.S. market, beyond the NYISO and the Ontario border. See *"Business of OPG – Regulation"*.

OPG will to continue to import and export energy. However, the new Market Rules require parties wishing to export electricity from Ontario to purchase energy from the Ontario spot market, and then 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). The following chart summarizes the various charges which are included in the export fee:

Export Fee Breakdown

Charge Type	**Description**	**Amount**
Export Transmission Service Rate	The rate is approved by the OEB and applies to the market participant who utilizes the transmission network to export to points outside Ontario in accordance with the Market Rules.	$1.00/MWh
IMO Administration Fee	A charge that is approved by the OEB and that applies to all market participants that withdraw energy from the IMO-controlled grid.	$1.00/MWh
IMO Uplift	IMO uplift charges include provisions for system losses, operating reserve, capacity reserve, congestion management (internal to Ontario), black start capability, reactive support and voltage control, regulation service, must run contract settlement, and outage cancellation/deferral. The IMO-published estimates of the individual uplift components vary over a wide range. Recent changes to the Market Rules may result in somewhat higher IMO Uplift costs. The full impact of these changes have not yet been determined.	$4.00 to $5.00/MWh
TOTAL		$6.00 to $7.00/MWh

Competitive Environment

Market participants licensed by the OEB have been positioning themselves for the new market, but it is not possible to predict how the market, including its sales channels and buying practices, will evolve. Given the anticipated operation of the electricity spot market, OPG believes that its competitive position will be most directly affected by its production cost relative to other generators both in Ontario and in the interconnected markets. This will be true particularly in off-peak periods, when OPG believes that generators in interconnected markets have more supply available and are cost-competitive with OPG. OPG believes that its cost of generation is, on an average short-run marginal production cost basis, lower than that of most other generators within Ontario and in many of its U.S. interconnected markets, although higher than generators in Manitoba and Québec.

In a competitive market, a variety of factors could influence OPG's low-cost position, such as the need for further investment in OPG's fossil generating facilities to comply with increasingly stringent limits on air emissions. In addition, other generators could offer power at prices below their full production costs in order to obtain market share in Ontario or in interconnected markets.

Total generation resources within Ontario in 2001 were approximately 151 TWh. Approximately 4.3 TWh of electricity was imported into Ontario and 4.1 TWh was exported from Ontario. This exported amount includes amounts exported pursuant to an electricity banking arrangement with Hydro Québec. The net result was that approximately 151 TWh of electricity was generated to meet consumption requirements in Ontario. This amount is approximately 12 TWh more than the amount consumed within Ontario, primarily as a result of transmission and distribution line losses.

OPG expects competitive pressures in Ontario to come from the following sources:

Companies which control generation capacity decontrolled by OPG. With the entry of Bruce Power, the decontrolled Bruce B units and any restarted Bruce A units will be a source of competition. However, base load energy from these units and from OPG's nuclear facilities have relatively low production costs and could be offered into the new Ontario market so as to be dispatched by the IMO at virtually all times, save for outage periods; as such, these facilities are not expected to set prices in the energy spot market. The announced sale of OPG's hydroelectric plants on the Mississagi River system and the planned decontrol of the Lakeview, Lennox, Thunder Bay and Atikokan fossil generating facilities will also create competition in the Ontario spot market. The Lakeview and Lennox facilities offer intermediate and peaking capacity and are dispatched when demand is higher. As a result, future operators of these stations can act as "marginal bidders" and therefore potential "price setters" at various times in the spot market to the extent not limited by emission allowances. The Thunder Bay and Atikokan facilities have historically been operated as either base load or intermediate capacity facilities, giving future operators of these facilities the flexibility to decide which type of operation is most appropriate for them. The Mississagi River system is generally run as a peaking system. This system has a large upstream storage reservoir, with a series of downstream generating stations, each having limited storage of their own. These stations have the ability to produce electricity to contribute to meeting peak demand throughout the year. The other OPG generating facilities which are to be decontrolled will also compete with OPG.

Intermediaries that offer new products and services, including financial risk management products. Intermediaries compete with OPG to sell energy products to end-users in Ontario by aggregating third party supply (domestic and imports) and spot market purchases, and by offering bundled value-added energy services or financial risk management services. Although intermediaries who participate in this market need not own generating facilities, owners of decontrolled assets will likely be competitors for the sale of these products as a means of managing their market risks. Intermediaries with expertise gained in other jurisdictions in the fields of aggregation and commodity marketing are particularly well-positioned for these opportunities. The success of these intermediaries depends on factors such as electricity price volatility and the development of a relatively liquid financial based market to facilitate pricing and product structuring. OPG believes that it can compete effectively with these intermediaries because of its familiarity with the Ontario market and the breadth of OPG's existing relationships with the target customers for these services. OPG also believes that certain customers may have a preference for purchasing financial risk management products from a counterparty with proven generating capacity and long-term customer relationships.

Imports of energy from the interconnected markets into Ontario. Intermediaries and other parties compete with OPG both for opportunities to source and import energy from outside Ontario, as well as for resale of imported energy to Ontario end-users. While these opportunities increase their competitive position, there are limits to the amount of energy that can be imported into or exported from Ontario due to physical and seasonal limits on the capacity of transmission inter-ties between and within jurisdictions. These factors periodically limit the ability of third parties, including low-cost producers such as Hydro Québec and Manitoba Hydro, to export energy into Ontario at certain peak times. However, Hydro One has been mandated to expand inter-tie capacity, including the announced 1,250 MW expansion of the inter-tie capacity between Ontario and Québec, and the proposed inter-tie of up to 975 MW between Ontario and Ohio and/or Pennsylvania. Although OPG is in a relatively strong position regarding its production costs, it is difficult to predict future electricity prices and other generators' bidding levels. In setting their prices, interconnected market generators will, however, be influenced by the price competitiveness of energy sold into the Ontario market, which will include the cost of transmission fees and losses applicable to transmission from the generation source to the Ontario border, the level of customer demand in Ontario and opportunities available to these sellers in other markets.

Generation by new independent power producers in Ontario. Whether new capacity will be built will depend on a number of factors, including actual and anticipated price levels and demand for electricity and natural gas, the ability of parties to structure economic transactions, technological advances, and environmental and other regulatory developments. If new facilities are constructed, they will compete with OPG and will have the potential to be price-setters in the energy spot market. New stations with aggregate capacity of up to 6,300 MW are currently proposed by other market participants.

Self-generation by wholesale customers. Interest in self-generation for load displacement or cogeneration by large industrial and commercial customers is expected to continue, particularly if they have a large requirement for steam. The attractiveness of these projects is influenced by a variety of factors, including the price of natural gas (the likely fuel type), power generation equipment availability, the ability to avoid transmission network service and IMO uplift charges, the rebate mechanism's effect on OPG's operations (thereby reducing the effective cost of energy to Ontario wholesale customers), or specific project economics which make self-generation viable. Other factors that may influence the development of self-generation capacity include the availability of waste fuel, steam boiler replacement, energy self-sufficiency, environmental considerations, by-pass of rates or any shift from a uniform to a locational marginal energy pricing system in Ontario.

Commercial Strategy

OPG and other market participants are actively positioning themselves to compete in the new Ontario energy market. OPG has developed a bidding strategy for sales into the IMO market and is also building and maintaining its existing relationships with wholesale energy customers in Ontario through enhanced communication and education programs.

OPG's Ontario-based energy production is offered into the IMO-administered market in order to be dispatched at the spot market price, and the largest part of OPG's revenue will be derived from this source. A significantly smaller but growing portion of revenue will be earned through the sale of bilateral financial contracts, new products and services designed to help customers better manage their energy needs, operating reserve, other ancillary services and must-run contacts with the IMO.

OPG has developed and is actively marketing new customer pricing options, products and services to wholesale and retail customers in Ontario. Specifically, a portfolio of risk management products and supporting services for bilateral transactions, such as forwards, swaps, load-following bilateral products and billing, reporting and verification services have been developed to meet customers' needs for energy procurement solutions. OPG is developing more new products and services to become a leading supplier of energy solutions in the competitive Ontario market. New information systems and enhanced or redesigned business processes and operations, such as energy trading and risk management operations are being implemented to ensure that OPG possesses the resources, required skills, corporate culture and customer service focus which are critical to its success in the competitive market.

Spot market prices fluctuate, at times significantly, at different time periods which relate to variations in electricity market demand. The highest spot market prices are set at periods of peak demand, typically set by the plants at the margin (usually natural gas generators) in the winter and summer months. Typically, at off-peak periods through the spring and fall, spot market prices are set by unit capacity further down the merit order ranking and are typically driven by coal-fired generation. Spikes in spot prices are, to the greatest extent, weather driven, usually reflecting a peak in demand combined with a shortage in energy, generation capacity or transmission and, depending on the jurisdiction, may be subject to a price cap set by the regulator. Due to the fact that the Ontario market is adjacent to several interconnected energy marketplaces and prices in interconnected markets are expected to move toward equilibrium, prices in Ontario are influenced by market conditions in other energy markets and available peak supply.

OPG's spot market strategy for the sale of OPG's Ontario-based energy production is to bid all available units into the energy and operating reserve real-time Ontario markets. The IMO optimizes energy and operating reserves to minimize the overall cost to the market. Actual market clearing prices are dependent on supply and demand. OPG's overall strategy also includes selling energy into other markets, such as the NYISO, depending on market conditions.

Over time, customer expectations and demand for risk management products will evolve as some customers seek more complete customized solutions and others shift to self-manage their price and volume risks and deal directly with trading desks. Given these market dynamics, OPG anticipates the market for bilateral financial transactions in Ontario will start somewhat slowly but increase significantly during the first five years after Open Access. Maintaining a strategic level of flexibility in markets, products and services is critical for OPG's success in these transactions in order to adapt to the high degree of uncertainty in the future environment. This in turn is impacted by factors such as the pace of competition and rate of customers switching away from Standard Supply

Service, OPG decontrol activities, the resultant level of rebates to customers under the market power mitigation framework, spot market price volatility, customers' price-risk tolerances, and changing purchasing preferences of OPG customers.

OPG's goal is to be a leading supplier of bilateral financial risk management products to selected wholesale and large retail customers in Ontario and interconnected markets. OPG recognizes that its success in offering financial risk management products and services is predicated on a variety of factors including: sophisticated product structuring and risk management skills in order to correctly price and manage complex structured products; marketplace relationships and brand equity to facilitate customer acquisition and retention; and superior understanding of customer needs in order to structure energy solutions, including associated services, which best meet customer needs, as well as the capability to deliver such solutions. Further, OPG recognizes that traditional segmentation based on size, industry category or type of business is not fully indicative of customer behaviour in a competitive market. In light of these market realities, OPG has taken a focused approach in targeting markets and customers for sales of OPG financial products and services based on those customers' expressed need for energy solutions. OPG will continue to invest resources in developing its trading, risk management and power marketing capabilities to position itself for success in Ontario and growth into contiguous markets.

Management of Commercial Risks

Overview

OPG's risk management activities involve identifying, assessing and controlling the risk associated with its portfolio of generation assets in an effort to optimize asset returns. The Board of Directors approves all risk management policies prior to implementation. OPG undertakes ongoing assessment of its risk exposures in order to characterize and quantify such exposures and the effects of risk management activities. Executive management and the Board of Directors review OPG's residual exposure to ensure it is consistent with overall corporate strategy and risk tolerance levels.

In a competitive market, OPG is subject to increased risk, including market and credit risk inherent in the market. Under the direction of the Board of Directors, a Risk Oversight Committee consisting of senior officers from OPG has been established to approve the framework for transactions, monitor policies and compliance issues, and ensure overall corporate governance specifically related to market activity for OPG.

In anticipation of increased levels and complexity of market activities, OPG has implemented comprehensive trade capture and risk management systems with related processes and controls. These processes include a segmentation of portfolio activities to facilitate effective identification and measurement of risks, and the application of appropriate position and risk limits. The methodology used to measure these risks involves the use of comprehensive and recognized risk tools for the monitoring of trading activities and the generation portfolio. See *"Business of OPG – Risk Factors"*.

Electricity Price Risk

Electricity price risk is the risk that changes in the market price of electricity will adversely impact OPG's earnings and cash flow from operations. OPG's production is exposed to spot market prices. However, initially a significant portion of OPG's electricity sales in Ontario are subject to an average annual revenue cap of 3.8 cents per KWh. . Any excess earned by OPG must be rebated to Ontario energy consumers via the IMO. The amount of energy sales that would be subject to the rebate mechanism from Open Access to 2004 has been predetermined on an annual basis and ranges from approximately 102 to 106 TWh, and will be reduced, with the approval of the OEB, as OPG reduces its control of generation capacity in Ontario. For example, the amount that would have been subject to the rebate mechanism for 2001 was 105 TWh (equivalent to 77% of OPG's 2001 energy sales in Ontario). In addition, derivative instruments and the sale of risk management products to end-use and wholesale customers may also be used to mitigate OPG's exposure to fluctuating electricity prices.

Price risk is increased in a market that lacks liquidity, through higher price volatility and hedging costs. Market liquidity is expected to be low for a period of time after Open Access and to improve over time as new entrants and existing participants identify opportunities in the marketplace. See *"Business of OPG – Regulation – Ontario's Electricity Industry – Market Power Mitigation/Decontrol – Rebate Mechanism and Transitional Price*".

Generation Risk

OPG is exposed to the market impact of unforeseen changes in output from its generating units, or generation risk. The amount of electricity generated by OPG is affected by such factors as fuel supply, water availability, equipment malfunction, physical security threats, and regulatory and environmental constraints. To manage these risks, OPG enters into multiple short-term and long-term fuel supply agreements and long-term water use agreements, manages fuel supply inventories, follows industry practices for maintenance and outage scheduling, 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. The water available for hydroelectric generation can vary greatly from year to year and hence there is a risk that a shortfall would result in a lost revenue opportunity. OPG continues its efforts in the areas of physical security upgrades and development of defensive strategies designed to protect against hostile activity described in recent CNSC documents that were prepared in response to the World Trade Centre attack. See "*Business of OPG – Generation Operations – Nuclear Operations – Pickering A Lay-Up and Restart*".

Liquidity Risk

OPG operates in a capital-intensive business and its initiative to return its Pickering A station back to service requires significant financial resources, the majority of which OPG expenses during the year in which they are incurred. Furthermore, any acquisition or development project may require access to substantial capital from outside sources on acceptable terms. OPG may also require external financing to fund capital expenditures necessary to comply with air emission or other regulatory requirements.

OPG's ability to arrange debt financing and the costs of debt capital are dependent on a number of factors including: (i) general economic and capital market conditions; (ii) credit availability from banks and other financial institutions; (iii) its maintenance of acceptable credit ratings; (iv) its relationship with the Province as the sole shareholder of OPG; and (v) the status of electricity market deregulation in Ontario.

OPG has not yet accessed the public debt markets, although it intends to do so. Future financings, including public debt financing, may include terms that are more restrictive than those applicable to OPG's existing credit arrangements.

Credit ratings are intended to provide investors with an independent measure of the credit quality of an issue of securities. Both Standard & Poor's Ratings Services ("S&P") and Dominion Bond Rating Service Limited ("DBRS") rate long-term debt instruments by rating categories ranging from a high of "AAA" to a low of "D". Long-term debt instruments which are rated in the BBB+ category by S&P are considered to exhibit adequate protection parameters, although adverse economic conditions or changing circumstances are more likely to lead to an issuer's diminished capacity to meet its financial commitment on the obligation. Long-term debt instruments which are rated in the "A" category by DBRS are considered to be more susceptible to adverse economic conditions and have greater cyclical tendencies than higher rated issuers. OPG is currently rated BBB+ by S&P and is in the A category by DBRS. Maintaining an investment-grade credit rating is essential in order to ensure broad access to capital markets and to facilitate energy and financial product sales and trading activities and will be a key factor for OPG going forward.

With the deregulation of the electricity market in Ontario, OPG is engaged in energy trading activities whereby certain counterparties can request that OPG provide collateral to secure various contractual or statutory obligations of OPG. The amount of collateral that OPG must provide may increase if OPG's credit rating is downgraded. If a counterparty requests collateral or additional collateral from OPG and OPG does not provide the required collateral within the time frames specified in the underlying contract or statute, it may trigger an event of default, potentially accelerating the aggregate indebtedness owed by OPG.

OPG's liquidity risk is managed by OPG maintaining appropriate credit facilities to ensure that OPG has the ability to respond to requests for collateral and finance its business. OPG is subject to restrictions on its ability to give collateral under the negative pledge provisions of its credit facility, and expects that similar provisions would be included in any public debt financing. Depending on OPG's performance and market conditions at the time, OPG may not be able to arrange for necessary financing on terms that are acceptable to OPG.

Generation Operations

Overview

OPG's portfolio of generating facilities as of December 31, 2001 consisted of 22,657 MW of net in-service capacity comprised of 7,369 MW of hydroelectric capacity, 9,700 MW of fossil capacity and 5,588 MW of nuclear capacity (excluding the facilities leased to Bruce Power), plus further nuclear installed capacity of 2,060 MW that is currently laid up. This represents approximately 32.5%, 42.8% and 24.6%, respectively, of the total generation capacity controlled by OPG. 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 generating licence, OPG has committed to decontrol at least 4,000 MW of fossil net generating capacity within 42 months after Open Access (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 the beginning of Open Access. To meet these requirements, OPG has decontrolled certain of its assets and is in the process of decontrolling others. To date, it has leased the Bruce A and B nuclear generating stations to Bruce Power effective May 2001, and on March 8, 2002, OPG announced it had reached agreement to sell its Mississagi hydroelectric plants to Brascan Corporation for $340 million. This transaction is expected to close during the second quarter of 2002.

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. OPG's hydroelectric plants are very competitive with generation in OPG's regional market area.

Generating Facilities

Generally, hydroelectric stations are grouped geographically and are operated on a river system basis rather than as stand-alone units. OPG's 69 hydroelectric generating stations, comprising 7,369 MW of capacity, and associated 245 dams are located on 27 river systems in Ontario.

Five Year Hydroelectric Capability, Capacity and Generation

	1997	1998	1999	2000	2001
Capability Factor (%)................................	89	90	91	92	93
Net Capacity Factor (%)............................	57.7	49.8	52.9	54	53
Net Energy (TWh)	36.4	31.9	33.6	34.0	33.7

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 1998, 1999, 2000 and 2001 the relatively low values for net energy and lower capacity factor were due to unusually low water availability arising from greater than normal evaporation and lower than normal precipitation.

A significant portion of OPG's hydroelectric production, representing 40% of total hydroelectric capacity and 51% of hydroelectric energy production in 2001, is produced at OPG's three largest stations located on the Niagara and St. Lawrence Rivers. In 2001, the two Sir Adam Beck stations on the Niagara River provided 1,925 MW of capacity, representing approximately 26% of OPG's hydroelectric capacity, and 11.0 TWh of energy production, representing approximately 33% of OPG's hydroelectric energy produced. On the St. Lawrence River, the R.H. Saunders station provided 1,035 MW, or 14%, of hydroelectric capacity and 6.1 TWh, or 18%, of hydroelectric energy produced in 2001.

Summary of Hydroelectric Generating Facilities and Performance (2001)

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	6.8%	1.7	5.2%	1922 – 1930
	Sir Adam Beck II	16	1,426.6	19.4%	9.1	27.2%	1954 – 1958
	Sir Adam Beck PGS[2]	6	174.0	2.4%	(0.1)	(0.4%)	1957 – 1958
	DeCew Falls I and II	6	166.8	2.3%	1.1	3.2%	1898 – 1948
	Ontario Power[3]	0	0	0.0%	0.0	0.0%	1905 – 1912
St. Lawrence River							
	R.H. Saunders	16	1,035.0	14.0%	6.1	18.0%	1958 – 1959
Ottawa River							
	Otto Holden	8	243.0	3.3%	1.2	3.5%	1952 – 1953
	Chenaux	8	144.0	1.9%	0.7	2.2%	1950 – 1951
	Chat Falls[4]	4	96.0	1.3%	0.5	1.5%	1931 – 1932
	Des Joachims	8	429.0	5.8%	2.3	6.7%	1950 – 1951
Madawaska River		15	615.0	8.3%	0.7	2.2%	1917 – 1977
Abitibi River		9	501.0	6.8%	1.9	5.7%	1933 – 1963
Mattagami River		19	487.0	6.6%	2.3	6.7%	1911 – 1966
Mississagi River		8	488.0	6.6%	0.8	2.4%	1950 – 1970
Other Rivers		116	1,066.0	14.5%	5.4	15.9%	1900 – 1993
Subtotal[1]		249	7,369.2	100%	33.7	100%	
Water Transfers and Unit Rentals[5]					(0.5)		
Total (Net of Transfers)[5]		249	7,369.2[6]	100%	33.2	100%	

Notes:

(1) Capacity and production information is provided as at or for the year ended December 31, 2001. 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 periods 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 2001 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 0.5 TWh in the aggregate.

(6) Reported net in-service capacity has increased by 59 MW to reflect hydroelectric upgrades during 2001.

OPG's hydroelectric generating stations range in age from nine 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 and dams, as regular maintenance and the replacement of specific components typically extend station service lives for very long periods.

Facility Planning

OPG employs a portfolio approach to facility planning and maintenance and has grouped its 69 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. 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 1990s, 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 through eight control centres.

OPG has spent over $1 billion since 1990 to refurbish and upgrade several of its hydroelectric facilities. This reinvestment program is continuing, with approximately $400 million expected to be spent over the next five years. These upgrading initiatives have increased hydroelectric capacity by approximately 330 MW since 1990.

Water Rental 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 "*Business of OPG - Regulation - Water Rights*".

OPG makes payments ("water rental payments") for the use of Crown lands. Water rental payments are calculated based on electricity produced at the relevant facility that results from the use of water (and not a different type of fuel such as oil or gas). Rental rates for 45 of OPG's hydroelectric stations (not including OPG's four stations on the Niagara River) were formerly covered by a master agreement with the Province. Rental rates for OPG's four stations on the Niagara River were formerly covered by an agreement between OPG, the Province and the Niagara Parks Commission. The water rental payments formerly assessed under these agreements have been replaced by the water rental portion of the new provincial gross revenue charge which came into effect on January 1, 2001 – see "*Business of OPG - Relationship with the Province and Others - Special Charges on Hydroelectric Generating Stations*". In addition to the water rental portion, the gross revenue charge also contains a proxy property tax component.

Other stations are covered by separate agreements and payments are made to the various parties with jurisdiction over those stations according to the terms specified in such agreements. The Federal Government receives rental 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 water rental payments are made, as there are no Crown leases related to these stations. OPG's final water rental payment for 2001 is due on May 16, 2002. Although the amount owing in respect of this final payment has not yet been finalized, OPG anticipates that aggregate water rental payments including the water rental portion of the gross revenue charges in respect of 2001 will be between $120 million to $125 million for all of its hydroelectric stations. Of this amount, approximately $115 million is the portion paid under the new gross revenue charge regime. The remaining balance of $10 million is for water rental 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 revenue from available water while meeting legal, environmental, and operational requirements.

Dam Safety Program

OPG operates 245 dams in connection with its hydroelectric generation operations. An additional eight dams are maintained in conjunction with OPG's fossil generation operations. OPG recently reviewed its dam inventory and has started to conduct a variety of safety assessments. The review considered among other criteria, the size and function of the structures relative to the definition of a dam under the *Lakes and River Improvement Act* (Ontario). Of these 245 dams, 20 are associated with the stations that are part of OPG's current decontrol plans (13 are associated with the Mississagi River stations and seven are associated with the Atikokan fossil station). OPG's dams are operated and maintained in a manner that meets or exceeds safety guidelines published by the Canadian Dam Association. None of OPG's dams have failed in over 90 years of operation.

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. OPG has spent approximately $67 million since 1988 on dam improvements and plans to spend approximately $35 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 develop a dam safety regulation under the *Lakes and Rivers Improvement Act* (Ontario). 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 the proposals. It is, therefore, difficult to determine the specific impact of this proposed regulation on OPG. 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 is aware that it will not always be feasible or reasonable for owners of existing dams to physically upgrade all dams that do not strictly meet the new criteria. The proposed regulations, therefore, allow owners of dams to submit a "Dam Safety Management Plan" to the MNR. These plans can include measures to enhance safety by means other than full structural upgrades, and therefore would be significantly less costly than strict compliance with the proposed design flood criteria.

It is expected that the option of Dam Safety Management Plans will be used extensively by OPG and other dam owners. The feasibility and acceptance by the MNR of Dam Safety Management Plans will be subjective and can only be addressed on a case-by-case basis. OPG believes, however, that in most cases, it will be able to develop Dam Safety Management Plans that will be acceptable to the MNR.

Expansion and Development

Due to the design of some of its Niagara River generating stations, OPG does not currently have the mechanical capability to efficiently use all of the water available to it. OPG mitigates the impact of these limits through a capacity rental arrangement with the New York Power Authority under which the parties share additional power generated by the New York Power Authority using OPG's water rights.

OPG has evaluated a number of alternatives to maximize its use of available water on the Niagara River. In 1998, provincial environmental assessment approval was granted for the Niagara River Development Project which, if undertaken, would consist of two new diversion tunnels extending from the Niagara River upstream of Niagara Falls to the Sir Adam Beck site, a powerhouse and associated transmission facilities. The first stage of the project, including construction of one of the diversion tunnels, would take four years to complete and would cost approximately $600 million. The remainder of the project would require five years to complete and would cost in excess of $1.2 billion. OPG regularly reviews the economics of this project but does not currently plan to begin its development.

Hydroelectric Station Decontrol

On March 8, 2002, OPG announced it had entered into an agreement of purchase and sale with Brascan Corporation in respect of OPG's four hydroelectric stations on the Mississagi River, located approximately 70 km east of Sault Ste. Marie. The four stations, Aubrey Falls (162 MW), G.W. Rayner (46 MW), Wells (239 MW) and Red Rock Falls (41 MW), provide net in-service capacity of 488 MW and total average annual energy (averaged over a 30 year period) of 0.76 TWh. The Mississagi River system is generally run as a peaking system, except Red Rock Falls, which also operates during non-peak hours. The transaction is expected to close in the second quarter of 2002, subject to regulatory approvals.

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 a key 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. Through major investment in pollution control technologies, emission rates of oxide of nitrogen ("NO_x") and sulphur dioxide ("SO_2") from OPG's fossil plants have been substantially reduced. Continued investment to meet prospective Ontario and U.S. regulatory standards will bring further reductions in emission rates and in actual emissions. Recent regulations enacted by the Province set new emission caps at OPG's fossil stations for 2002 limiting SO_2 and NO_x emissions and such caps over the next five years and will require additional investment in emission control technology and fuelling strategies. See *" Business of OPG – Environmental Matters – Management of Air Emissions – Fossil Operations"*.

Generating Facilities

OPG currently owns and operates six fossil stations. A total of 23 fossil generating units were in-service during 2001 with a combined net in-service capacity of approximately 9,700 MW, representing approximately 42.8% of OPG's total in-service capacity in 2001 (i.e. excluding Pickering A, which was laid up). Coal-powered generating units located at Nanticoke, Lambton, Lakeview, Thunder Bay and Atikokan account for approximately 7,560 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

	1997	1998	1999	2000	2001
Capability Factor (%)	65.8	74.4	68	76	71
Net Capacity Factor (%)					
Coal	37	51.8	51	62	56
Oil/Gas	1.9	6.5	12.3	6.4	16.7
Net Energy (TWh)	24.4	34.2	36.1	42.4	40.2

The increase in fossil capacity factors and total energy produced between 1997 and 2001 was due to increased coal-fired generation used to compensate for declines in nuclear generation from the lay-up of units under the nuclear recovery plan. The two scrubber-equipped units at Lambton 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 emissions. For example, in order to reduce OPG's NO_x emissions, 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 control to reduce NO_x emissions at Lambton and Lakeview. See "*Business of OPG – Environmental Matters – Management of Air Emissions – Fossil Operations"*.

Summary of Fossil Generating Facilities and Performance (2001)

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)	Estimated Retirement Date(2)
Nanticoke(3)	8	3,920	40	21.2	53	1973-1978	2015
Lambton(3)	4	1,975	20	10.4	26	1969-1970	2010-2020(4)
Thunder Bay(3)	2	310	3	1.6	4	1981-1982	2021
Atikokan(3)	1	215	2	0.8	2	1985	2025
Lakeview(3) (5) (6)	4	1,140	12	3.0	7	1962-1969	2005
Lennox(5) (7)	4	2,140	22	3.2	8	1976-1977	2016
Subtotal	23	9,700	100	40.2	100		
Total Excluding Lakeview and Lennox, Thunder Bay and Atikokan…………..	12	5,895		31.6			

Notes:

(1) Capacity and production information is provided as at or for the year ended December 31, 2001. Net energy is the energy produced by the station less energy consumed by the station.
(2) Estimated retirement date is based on the average in-service date of units at the station and an estimated service life of 40 years except as noted.
(3) All units are coal-fired.
(4) Service lives for Lambton units 3 and 4 have been extended to 50 years as a result of extensive plant rehabilitation.
(5) OPG intends to decontrol approximately 4,300 MW of generating capacity, 3,800 MW at the Lennox, Lakeview, Thunder Bay and Atikokan fossil generating stations and 500 MW at the hydroelectric generating stations.
(6) 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 recent Provincial regulation requires Lakeview to cease burning coal by 2005.
(7) Lennox units are dual-fuelled (oil/natural gas).

Fossil Station Decontrol

In response to a request from the Minister, OPG is accelerating the planned decontrol of approximately 3,800 MW of fossil capacity, at Lakeview, Lennox, Thunder Bay and Atikokan. Lakeview has operated mainly as an intermediate to peaking plant. A recent Provincial regulation requires Lakeview to cease burning coal by April 2005. Lennox, converted to dual-fuel, has operated predominately during peak periods. The Thunder Bay and Atikokan facilities have historically been operated as either base load or intermediate capacity facilities. See "*Background – Ontario's New Electricity Market – Market Power Mitigation*".

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.

The large temperature and pressure variations experienced during cycling operation of fossil units to meet system peaks cause more mechanical wear than continuous operation. For example, between 1995 and 1997, when the fossil stations were used primarily for peaking loads, OPG had an excess of capacity, so forced outages did not have a significant supply impact. 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 might otherwise be 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.

OPG has recognized, and carries on its balance sheet, a provision to cover future costs of decommissioning and dismantling each fossil station. This provision is valued at approximately $90 million at December 31, 2001 and is not currently funded. Approximately $26 million of these decommissioning costs are associated with the two fossil plants, Nanticoke and Lambton, which will remain with OPG after the planned decontrol of the other four fossil plants. In establishing this provision, OPG has used 50 years as the expected service life for the two Lambton units where scrubbers have been installed and 40 years for the other fossil units.

Fossil Fuel Procurement

Coal is the fuel used at all of OPG's fossil generating stations except Lennox. Fuel and related transportation costs in 2001 accounted for approximately 80% of the total production cost of OPG's fossil generation. In 2001, OPG's total fossil fuel and related transportation costs amounted to $1,031 million, 79% of which was for coal. Approximately 85% of these costs in 2001 represented purchases in the United States or denominated in U.S. dollars. OPG's fuel unit energy costs generally declined in the period from 1995 to 2000 as a result of declining commodity prices, increased supplier competition and equipment modifications that enable the facilities to burn a broader range of coal types, although this was somewhat offset by the declining value of the Canadian dollar relative to the U.S. dollar over the same period. The price of coal started to increase in the last quarter of 2000, peaking about mid-2001. Current prices, while lower than the peak, remain above pre-2001 levels and have been volatile. In addition, OPG's purchases are made on a variety of short to medium term bases. As a result, OPG anticipates that it will have higher fuel unit energy costs in 2002 relative to prior years.

Approximately 88% of the coal used at OPG's fossil stations in 2001 was shipped by way of the Great Lakes. OPG maintains a seasonal inventory of coal at each of its coal-fired stations that is sufficient to meet forecast energy requirements during the winter months, typically mid-December to mid-April, when Great Lakes shipping lanes are closed.

OPG's fossil fuel 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 is used as a generation fuel at OPG's Lennox generating station. Approximately 13% of the volume of natural gas purchased in 2001 was purchased pursuant to a long-term supply contract. This supply is shipped by firm pipeline capacity from Alberta to Lennox. The rest of the natural gas requirements are fulfilled by spot market purchases in Ontario. In 2001, OPG's total purchases of natural gas cost approximately $143 million.

The residual fuel oil for OPG's 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. There are no long-term oil purchase agreements in place. Because of the requirement for low sulphur oil (under 0.7% sulphur content), the oil is purchased from offshore sources; 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 2001, these residual fuel oil purchases cost approximately $74 million.

Air Emissions and Effective Generation Limits

OPG's current in-service fossil generating units are theoretically capable of generating a total of 85 TWh annually, based on each unit running at its maximum capacity, 365 days per year. However, because of the need to carry out routine and unexpected maintenance and regulatory inspections, these units are limited to a maximum generating capability of approximately 60 TWh annually. OPG's fossil generation, prior to OPG decontrolling any fossil facilities, is effectively limited to approximately 45 TWh annually because of environmental regulations, the emissions characteristics of these units and the merit order of dispatch of units. The Nanticoke and Lambton facilities that would remain with OPG after the planned decontrol of the Lakeview, Lennox, Atikokan and Thunder Bay facilities are capable of generating approximately 52 TWh annually; however, environmental regulations effectively restrict generation for these units to approximately 35 TWh in 2002 (based on OPG's current emission control program).

The burning of fossil fuels gives rise to a number of emissions, principally sulphur dioxide ("SO_2"), oxides of nitrogen ("NO_x") and carbon dioxide ("CO_2"), as well as mercury and particulate matter such as dust and ash. 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. Greenhouse gas emissions contribute to global warming. The primary greenhouse gas emission resulting from OPG's operations is CO_2. National and international initiatives to reduce greenhouse gas emissions are ongoing and may result at some point in the future in the introduction of regulatory limits on greenhouse gas emissions.

Regulatory limits on emissions have been supplemented by voluntary caps on emissions implemented by OPG as part of its commitment to reduce adverse environmental impacts of its operations. Regulations will continue to evolve as more is learned about the effects of these emissions on the environment and as national standards are adjusted to reflect changing international standards. See *"Business of OPG – Environmental Matters – Management of Air Emissions – Fossil Operations"*.

In 2001, OPG's fossil facilities generated 40.2 TWh of energy, resulting in 44.6 Gg of NO_x emissions. Through the use of emission reduction credits, OPG was able to offset 6.6 Gg of NO_x emissions and meet its voluntary 38 Gg NO_x limit, thereby allowing OPG to generate a further 6.0 TWh of electricity that would not otherwise have been possible in compliance with its emission limits. 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, emission reduction credits and total fossil energy production.

Five Year Fossil Production and Air Emissions

	1997	1998	1999	2000	2001
Net energy (TWh)(1)	24.4	34.2	36.1	42.4	40.2
SO_2 emissions (Gg)					
OPG emissions	123.6	143.0	142.1	164.1	149.0(2)
Emission reduction credits	N/A	N/A	N/A	N/A	N/A
Regulatory Limit (gross)	175.0	175.0	175.0	175.0	175.0(3)
NO_x emissions (Gg)					
OPG emissions	43.1	55.8	51.4	50.5	44.6(2)
Emission reduction credits	N/A	N/A	N/A	12.5	6.6
Voluntary Limit (net)	N/A	N/A	N/A	38.0	38.0(3)
Total Acid Gas Emissions (Gg)	166.7	198.8	193.5	214.6	193.6(2)
CO_2 emissions (Tg)					
OPG emissions gross	23.5	31.0	32.2	38.5	37.0
Emission reduction credits	N/A	N/A	N/A	12.5	N/A
Voluntary Limit (net) (3)(4)	N/A	N/A	N/A	26.0	26.0

Notes:

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

(2) Prior to 2002, the Province had limited OPG's annual SO_2 and NO_x emissions to 215 Gg in aggregate and annual SO_2 emissions to 175 Gg.

(3) O. Reg. 397/01 – Emissions Trading, which came into force on December 31, 2001 (discussed in more detail below) has reduced the limits for OPG's SO_2 emissions to 153.5 Gg annually in 2002 and 2003, net of emission reduction credits used, and reduced the annual limits for NO_x emissions to 35 Gg in 2002, decreasing to 21.1 Gg in 2006, net of emission reduction credits used. Prior to implementation of these new limits, OPG had 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.

(4) For 2000 and beyond, OPG has also voluntarily committed to stablize its CO_2 emissions, net of emission credits used, to levels equivalent to the 1990 baseline. The timeframe for reconciliation of gross and net CO_2 emissions in the period 2001 to 2007 has been extended from 2002 to the end of 2007.

The Province enacted regulations in 2001 limiting annual SO_2 emissions from the Ontario electricity sector to 153.5 Gg, for the period 2002 to 2003. Starting in 2004 this limit will apply to the Ontario electricity sector as a whole. This limit decreases to 127.0 Gg of SO_2 annually in 2007 and beyond.

The Province has indicated that Ontario NO_x requirements will meet or exceed United States requirements. The Ontario regulations limit NO_x emissions from 2002 to 2006 to 35 Gg, net of emission reduction credits. Starting in 2007 these regulations provide that NO_x emissions from Ontario's electricity sector will be limited to 27 Gg annually, net of emission reduction credits. The Ontario regulations also establish an additional 1 Gg of emission reduction credits that may be obtained (and sold, at the discretion of the party receiving such credits) for renewable and energy efficiency projects.

OPG's SO_2 and NO_x emissions in 2001 were within applicable regulatory limits. However, OPG's 2001 SO_2 and NO_x emissions exceeded the new limits that have come into effect in 2002. To meet its obligations under applicable environmental regulations and objectives, OPG has implemented a range of air management initiatives to monitor and reduce air emissions from its fossil generating stations. OPG spent approximately $90 million between 1999 and 2001 to reduce NO_x emissions, by almost 40% of the 1997 emission rate. OPG is also installing four selective catalytic reduction ("SCR") units at Lambton and Nanticoke over the next two years at an estimated cost of approximately $285 million.

OPG has a number of options available to meet its NO_x emission limits without limiting the amount of electricity that OPG can generate and sell during the year. First, with the development of an emission reduction trading program, OPG could, subject to an upper limit of one third of its allowance levels, obtain and use emission reduction credits to offset any NO_x emissions that exceed the limit up to a maximum of 33% over the total allowances. It is anticipated that current levels of generation from the fossil plants currently controlled by OPG (in the 40 TWh range) could be sustained in the short-term through the use of emission reduction credits. Second, OPG could reduce NO_x emissions through the installation of additional capital equipment such as SCR technology on targeted units. As mentioned above, OPG is installing SCR equipment on two units at the Nanticoke station and on two units at the Lambton station by the end of 2003, at a cost of approximately $285 million. This equipment is expected to reduce NO_x emissions by an additional 12 Gg per year. OPG has also installed low NO_x burners on all four units at the Lakeview station. OPG believes that the implementation of a combination of these options will be effective in providing the flexibility to meet its energy production requirements while still enabling OPG to meet reduced NO_x emission limits.

Although there has been considerable success in reducing SO_2 emissions from Canadian and United States sources, regulators in Canada and the United States have indicated that further reductions are required. The current Ontario regulation is described below. See "*Environmental Matters – Management of Air Emissions – Fossil Operations*".

SO_2 emission rates are directly related to the sulphur content and heat content of the fuel burned. OPG has primarily used higher-cost low sulphur coals to reduce SO_2 emissions while sustaining cost flexibility. The conversion of four oil-fired units at the Lennox station, which now have the capability to burn natural gas, also 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.

Mercury emissions from coal-fired generating stations are emerging 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 plans to develop a final electricity sector mercury regulation in 2004 with compliance to be achieved in 2007. Similarly, under the Canada Wide Standards setting process, a Canadian mercury emission standard for utilities is expected in 2002. No firm implementation date has been set. There is considerable uncertainty as to what specific standards will be established for permitted mercury emissions in part because currently available technologies are expensive, unproven in commercial applications and may not result in the permanent removal of mercury from the environment. Other technologies are being reviewed but are not yet proven. At this stage OPG has been actively involved in researching and funding the development of mercury emission control technologies. OPG also continues to work with government, stakeholders, academics and industry in addressing mercury emissions.

OPG continues to make modifications to equipment and operating controls that improve its coal combustion heat rate and improve the energy efficiency of all generating facilities, thereby reducing coal consumption and lowering CO_2 emission rates. OPG has voluntarily committed to reduce its CO_2 emissions, net of emission reduction credits, to levels equivalent to the 1990 baseline level. The timeframe for reconciliation of gross and net CO_2 emissions in the period 2001 to 2007 has been extended to the end of 2007. The cost of CO_2 emission reduction credits over this period has been capped by OPG at $60 million. Apart from equipment modifications and efficiency improvements, the only economic options currently available to OPG to meet its voluntary CO_2 emission commitments are to reduce fossil generation or to buy additional emission credits.

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 of electricity produced than fossil facilities.

Ontario's nuclear generating stations were designed to provide a significant portion of Ontario's base load generation capacity. OPG's in-service nuclear generating stations, each consisting of four units, provided approximately 40% of OPG's total production in 2001.

Generating Facilities

Energy produced at OPG's nuclear generating stations has generally declined over the past five years. This is as a result of a number of factors. Until 1997, OPG had five operating generating stations at three sites: Bruce A and B, Pickering A and B and Darlington. Their output is reflected in the figures for 1997 below. In 1998, Bruce A and Pickering A were laid up pursuant to OPG's nuclear recovery plan. See – "*Nuclear Recovery Plan*". Operating results from these two stations are excluded from the time they were laid up to the present. In 2000, the total energy generated declined in part due to the shut down of the Pickering B facility for five weeks due to a planned vacuum building outage. Such outages are required by regulation to occur every 10 years. On May 11, 2001, Bruce A and Bruce B were leased to Bruce Power and the output and performance of these stations has been excluded from the information presented in this annual information form after that date.

OPG currently operates Pickering A and B and Darlington. Pickering B and Darlington are operating and are reflected in the 2001 figures. Pickering A is still laid up but in the process of being restarted. See – *"Pickering A Lay-Up and Restart"*.

Five Year Nuclear Capability, Capacity and Generation

	1997	1998	1999	2000	2001
Net Capability Factor (%)	62	77	81	79	82
Net Capacity Factor (%)	61	76	81	78	81
Net Energy (TWh)	70.3	59.9	61.4	59.8	47.7

Summary of Nuclear Generating Facilities and Performance (2001)

Station	No. of In-Service Units	Net In-Service Capacity per Unit (MW)(1)	Net In-Service Capacity (MW)	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	84.7%	26.1	55	1990-1993	2022-2025
Pickering A(3)..........	0/4(4)	515	2,060	0%	(0.1)	0	1971-1973	2011-2013(5)
Pickering B.............	4/4	516	2,064	72.2%	13.1	27	1983-1986	2013-2016
Bruce A(3)(6)............	0/4	769	3,076	0%	(0.0)	0	1977-1979	TBD(7)
Bruce B(6)................	4/4	790(8)	3,160	87.5%	8.6	18	1984-1987	2012-2015
Subtotal.................	12/20(4)		13,884	81.3%(8)	47.7	100		
Total Excluding Bruce A and B…….	8/12 (4)		7,648	80.1%	39.1			

Notes:

(1) Net capacity and production information is provided as at or for the year ended December 31, 2001. Net energy is the energy produced by the station less energy consumed by the station.

(2) With the exception of Pickering A, 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 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 "- *Operating Life Assessment*".

(3) 5,136 MW of capacity was removed from service as a result of the short term lay-up of Pickering A and the longer term lay-up of Bruce A under OPG's nuclear recovery plan. See *"- Nuclear Recovery Plan"*.

(4) OPG is in the process of returning the four Pickering A units to service. See "- *Pickering A Lay-Up and Restart*".

(5) 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 operating condition of the existing steam generators.

(6) OPG entered into a long-term lease for the Bruce A and B stations, which closed May 11, 2001. Performance data for both Bruce A and Bruce B are therefore for the period January 1 to May 11 only.

(7) Bruce Power has announced its intention to restart two of the four nuclear units at Bruce A. See "- *Bruce Decontrol*".

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

(9) Numbers may not add up exactly due to rounding.

Pickering A Lay-Up and Restart

One of OPG's key strategic initiatives is the restart of the four laid-up units of the Pickering A station. Following a hearing in 2001, the Canadian Nuclear Safety Commission (the "CNSC") amended the Pickering A licence to provide the pre-restart requirements. The CNSC must be satisfied that these requirements have been met prior to it authorizing the restart of each unit. OPG currently expects to return the first unit to service in late 2002 or early 2003, depending upon the results of commissioning and the time needed for regulatory approvals with the remaining three units currently anticipated to be added at approximately six to nine month intervals thereafter. The actual dates will be driven by a variety of factors including the actual levels of work execution in the field, which in turn can be impacted by the timely availability of materials and resources, and the success in the overall management of a project of this scope and complexity.

The restart initiative, while continuing to make significant progress, has faced major challenges. The specified improvements and upgrades requested by the CNSC in OPG's licence application for restart are more extensive than originally anticipated, and the overall implementation of the project is costing more and taking longer than initially planned. This relates to a variety of factors, many of which are implicit in a major refurbishment of this nature where the actual extent of many aspects of the project can only be firmly determined after work has progressed well beyond the initial stages. In part related to these factors, the engineering costs are significantly higher than anticipated and completion of engineering work has taken materially longer than planned, with a related impact on cost as well as scheduling and level of completion of work in the field. In addition, increased security requirements following September 11 have complicated the supply of labour and materials to the project. As a result, costs have increased. The total cost of the project, the majority of which is being expensed in the year in which it is incurred, is currently estimated at approximately $2 billion, of which approximately $600 million had been incurred as of December 31, 2001. The estimated additional cost to complete the first unit from December 31, 2001 is approximately $320 million. The remaining three units are estimated to be returned at an additional cost of $300 to $400 million each.

Operating Life Assessment

The initial design life for OPG's nuclear generating stations 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 which provide engineers with an assessment of the condition of such components relative to original design. Repeated inspection on 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 major component life cycle plan. OPG's current operating life estimates for its nuclear generating stations are based upon the results of this program to date and the previous operating history of the stations. OPG will continue to analyze information on the physical condition of its nuclear generating stations and develop correspondingly appropriate operational and maintenance activities.

In particular, as a key part of its nuclear recovery program, OPG has undertaken an ongoing program to assess the condition of key components of the system including its steam generators, fuel channels and related infrastructure including 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, 2001, 69% of OPG's steam generators (with 75% 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 has been deemed necessary to slow down the degradation rates. 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. A prognosis for the remaining life of each unit has been estimated and those at Pickering B will be most closely monitored. The life cycle management plans form the basis for the generation planning and budgeting from year to year.

Results from the fuel channel inspection program continue to support the end of life projections for the fuel channels. Maintenance activities at Pickering B to reposition the support springs in the fuel channels are planned over the next several years to ensure the end of life projections are achieved. 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 from the reactor to the steam generator. Thinning of feeder pipes occurs to varying degrees at all of OPG's reactors. If not mitigated, this situation may require replacement of selected pipes before the projected end of life. This condition is most significant at the Darlington plant, but also affects the Pickering A and B stations to a lesser degree. The results of OPG's inspections to date indicate that this will likely require an expenditure of approximately $50 million (total for four units at Darlington) and one to two months of additional outage time per unit, over the next decade. Mitigation options under development by OPG may extend feeder pipe life and significantly reduce the thinning rate. This strategy and its associated costs continue to be reviewed and revised as appropriate.

Feeder pipe cracking was recently experienced on two occasions at one CANDU plant located outside Ontario. The affected sections of pipe were replaced and the unit returned to service on both occasions. Extensive inspection was completed recently at a second plant located outside Ontario which did not reveal any evidence of cracking. OPG has not experienced any feeder pipe cracking at any of its nuclear facilities but is undertaking inspections during regularly planned outages. OPG believes that feeder pipe manufacturing differences may make OPG's feeder pipes at Pickering A and Pickering B less susceptible to this phenomenon.

Bruce Decontrol

Effective May 11, 2001, OPG leased its Bruce A and Bruce B nuclear generating stations and sold certain related assets to Bruce Power. Bruce Power is a limited partnership composed of British Energy (79.8% interest), an international energy company operating reactors in the United Kingdom and the United States, Cameco Corporation (15% interest), a Canadian uranium producer, and the two main unions on the Bruce site, The Power Workers'

Union (4% interest) and The Society of Energy Professionals (1.2% interest). Bruce Power has announced its intention to restart two of the four nuclear units at Bruce A, subject to certain conditions including receiving regulatory approval.

The operating lease has an initial term of approximately 18 years and includes options to extend the lease for up to another 25 years. As part of the initial payment, OPG received $370 million in cash proceeds and a $225 million note receivable. The note is due in two instalments of $112.5 million no later than four and six years from the date the transaction was completed. Under the terms of the lease, OPG transferred to Bruce Power materials, certain fixed assets, pension assets and liabilities and other post employment benefit obligations. Also, in conjunction with the terms of the lease transaction, OPG agreed to purchase all of Bruce Power's electricity generation up to the date the Ontario market opened to competition. OPG continues to be responsible for the nuclear fixed asset removal and waste management liabilities associated with the Bruce nuclear generating stations. Bruce Power is paying OPG a fee in respect of long-term management of any waste generated by Bruce Power's operation of the stations. OPG is responsible for plant decommissioning after the reactors have been defuelled and the heavy water is drained.

The lease payments OPG receives include monthly fixed payments and periodic variable payments. The variable lease payments include a net revenue-sharing arrangement which started in January 2002 and supplementary payments for the management of used fuel. In total, payments were approximately $70 million in 2001 and will be higher in 2002 as a result of the commencement of the variable component of the lease payment. In addition to the lease payments, OPG also receives other revenue for various services provided to Bruce Power, including the management of low and intermediate level waste.

The contribution to earnings from the Bruce nuclear generating stations decreased by $214 million before tax in 2001 compared to 2000. This amount includes the impact of the power purchased from Bruce Power, partially offset by lease and service revenue related to the lease agreement, and a decrease in operating expenses. The aggregate amount of the initial payment and annual lease payments to OPG over the term of the lease are estimated to be approximately $3 billion over the term of the lease. See "*Business of OPG – Risk Factors – Market Power Mitigation/Decontrol*".

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 1960s 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 and South Korea, and two units are under construction in 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.

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.

Nuclear Recovery Plan

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 contributed to declining nuclear production resulting from more frequent forced outages or extensions to planned outages. Maintenance backlogs grew and there were an increasing number of reportable events to the regulator, the Atomic Energy Control Board (now the Canadian Nuclear Safety Commission, "CNSC"), which in turn resulted in increased regulatory scrutiny. OPG implemented various recovery initiatives in the early 1990s to address these operating difficulties. These initiatives did not identify or deal with the underlying causes due to inadequate planning, co-ordination, resources and accountability.

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

The team classified OPG's nuclear operations as "minimally acceptable". 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. The team also found that OPG's inspection program for its steam generators was inadequate. The team concluded that existing safety margins were deemed sufficient to protect employees, the public and the environment but OPG would have to implement significant operational and management changes in order to avoid regulatory intervention and restore OPG's nuclear operations to industry-leading standards of safety and performance. The team determined that the design of the CANDU reactor was not a contributing factor to OPG's declining nuclear performance.

OPG's operational difficulties were not unique. The U.S. nuclear industry experienced similar problems in the 1980s, which were largely rectified through the adoption of enhanced operating practices and industry-wide knowledge-sharing practices which form the basis of the practices currently being implemented by OPG.

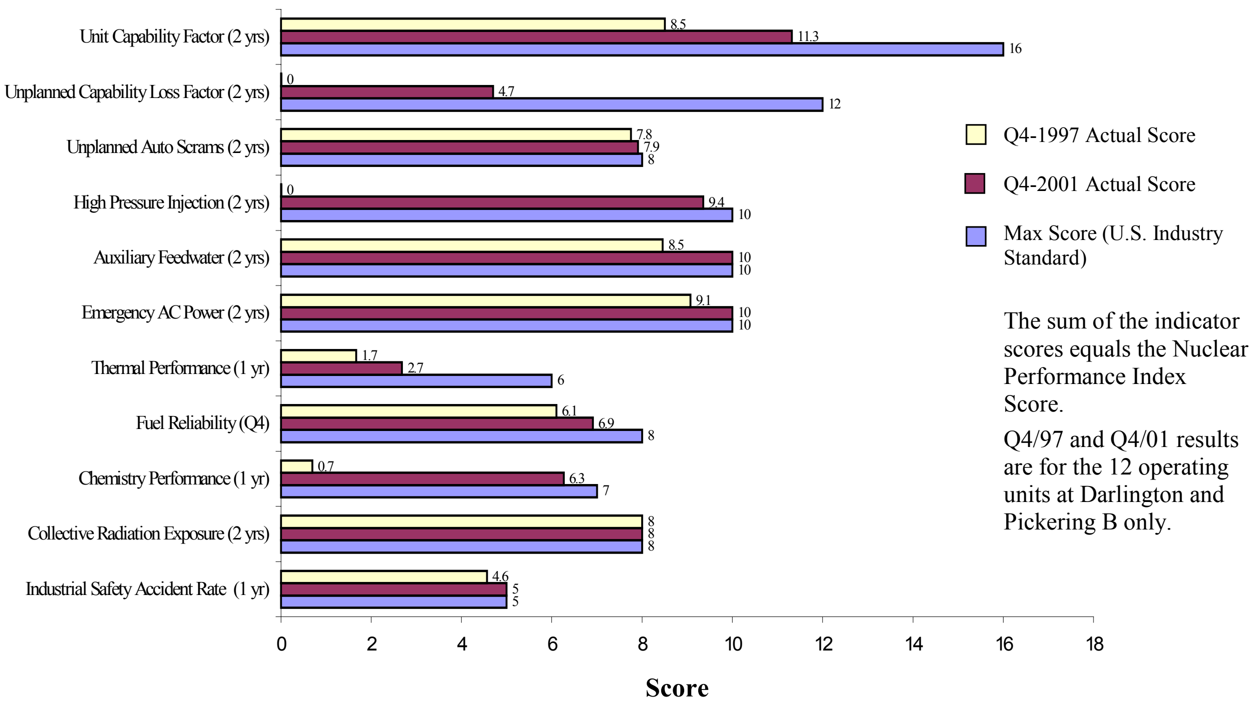
In conjunction with independent nuclear recovery experts, OPG developed in the fall of 1997 a comprehensive nuclear recovery plan to improve the operating performance of its nuclear generating stations over a seven year period. Under the plan, OPG is continuing to standardize its operations and implement initiatives to improve: accountability; management and operational control systems; maintenance and inspection programs; regulatory compliance; performance standards and employee training. OPG adopted a phased nuclear recovery strategy in order to focus qualified personnel and management resources on fewer units. As a result, the Pickering A station was placed in short term lay-up on December 31, 1997. This enabled OPG to focus its initial recovery efforts on the remaining eight nuclear generating units at the Darlington and Pickering B stations. See "- *Pickering A Lay-Up and Restart*".

Expenditures from the start of the program in 1997 to the end of 2001 were $1,040 million. Expenditures related to the nuclear recovery plan during the period from 1997 to 2004 are expected to total $1,400 million.

As part of its nuclear recovery plan, OPG has adopted the standard nuclear performance index ("NPI") sponsored by the American members of the Institute of Nuclear Power Operators ("INPO") and the World Association of Nuclear Operators ("WANO"). The NPI quantifies the performance of nuclear generating stations with reference to eleven performance indicators, two-thirds of which are related to safety and one-third to production. OPG reports its results quarterly and annually to WANO. The performance of OPG's eight in-service units at Pickering B and Darlington for 1997 and the fourth quarter of 2001, compared to the maximum NPI score possible, are set out in the following chart:

Nuclear Performance Index

Comparison of Component Indicators



OPG met or exceeded 30 of its 37 key nuclear performance targets for 2001, including the targets for safety and environment. The most significant target that was not met was that OPG's nuclear generation capability factor was less than its performance target, due to higher planned and unplanned outages at Darlington and Pickering B than had originally been budgeted.

Regulatory Affairs

OPG's nuclear operations are regulated by the Federal Government under the *Nuclear Safety and Control Act* (the "NSC Act"). In addition, OPG is subject to the *Nuclear Liability Act* (the "NLA").

The NSC Act, which replaced the Federal *Atomic Energy Control Act* effective May 31, 2000, updates the prior legislation which had been adopted in 1946 and broadens certain powers of the CNSC, the successor to the Atomic Energy Control Board, to regulate nuclear operators. All construction requirements, equipment, safety systems and operating limits for OPG's nuclear generation stations are subject to the approval of the CNSC. OPG is required to report regularly to the CNSC, which continually monitors the safety performance of OPG's nuclear generating stations. See *"Business of OPG – Regulation – Nuclear Regulation"*.

All of OPG's nuclear operating licences were reissued as of April 1, 1999 when OPG acquired the generation business of Ontario Hydro. The operating licences for Pickering A and B were renewed for a 27-month period expiring June 30, 2003. The Darlington operating licence was renewed for a term of 27 months expiring on February 28, 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 contains a clause which requires the approval of the CNSC to restart the Pickering A units. See *"– Nuclear Operations – Pickering A Lay-Up and Restart"*.

The NLA governs the liability of licensed operators of nuclear generating stations arising from prescribed nuclear incidents. The NLA provides strict liability to the operators for third party claims and requires these operators to purchase nuclear liability insurance from the Nuclear Insurance Association of Canada in specified amounts. Currently, OPG must maintain $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). The NLA also caps on the level of liability at the insurance level of $75 million per incident. The NLA is currently under review, which will likely result in a requirement for higher insurance coverage amounts consistent with trends in other countries with nuclear facilities. 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 have resulted in reductions on reactor power output (referred to as a "derate").

The reduced safety margins identified by the amended reactor physics codes have reduced OPG's operating margins and increased OPG's costs with respect to the operation of Darlington and Pickering A. All four units at Darlington continue to be derated to a maximum reactor power level of 98%. Modifications planned for completion this year were intended to allow the return of Darlington to 100% but safety analysis with the new codes is ongoing. It is possible that operation at 98% will have to continue with a small risk of further derating. The Pickering A units, when restarted, may also be derated to as much as 96% of their maximum reactor power level. Current estimates indicate that Pickering B will not be derated as a result of the new analysis. The CNSC may require that OPG implement design changes to the derated nuclear reactors before permitting OPG to resume operation at maximum reactor power levels. 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.

Ongoing work is being undertaken by OPG and other nuclear operators in an effort to restore operation at maximum power levels. This activity involves a combination of additional safety analysis, a redesign option study and proposing options for changing the licensing basis used for reactor regulation in Canada. The earliest that maximum reactor power levels could be restored at Darlington is estimated to be approximately July, 2002. If a significant redesign is required, restoration of full power conditions at Darlington may take as long as five years or more.

Nuclear Fuel Procurement

OPG has a diverse 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 and other Canadian-owned CANDU reactors.

Ancillary Operations

Heavy Water Management

OPG's nuclear generating stations contain approximately 7,000 tonnes of deuterium oxide or heavy water (not including heavy water contained at the leased Bruce stations), which is required to operate the CANDU reactors. OPG also owns approximately 1,300 tonnes of heavy water that has been designated as future use inventory. 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 has been decommissioned; the other ceased operations in 1997 and is expected to be fully decommissioned by the end of 2004. 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 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 moderator of CANDU reactors as a by-product of the nuclear fission process. OPG owns 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 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- and intermediate-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 *"Business of OPG – 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.

In December 1998, the Federal Government announced its response to the Seaborn Panel's report. The Federal Government Bill C-27, the *Nuclear Fuel Waste Act,* will require the producers and 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. Under this approach, the producers and owners of this radioactive waste would appoint the board of directors of this waste management organization and fund all of its activities by establishing a trust fund. The waste management organization would report to the Federal Government setting out its preferred approach to the long-term management of radioactive nuclear fuel waste. Bill C-27 was passed by the House of Commons on February 26, 2002. It is expected to come into force in mid-2002. In response to Bill C-27, OPG held discussions with the Province, the Federal Government and other Canadian nuclear waste producers regarding the establishment of a nuclear waste management organization for the life cycle management of nuclear fuel waste. A plan is in place to ensure that the waste management organization is operational when the legislation comes into force.

Current Management Practices

Bundles of used nuclear fuel from OPG's reactors are temporarily stored in water-filled pools known as "wet bays" at its nuclear generating stations for a "cooling-off" period of at least ten years during which 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, 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 only at the Pickering site. Construction of a used fuel dry storage system at the Bruce stations to provide additional storage capacity to the Bruce wet bays is in progress, with an estimated cost of approximately $40 million. This facility is planned to be in-service before the end of 2002. In-station modifications required to the Bruce B pools to support loading of used fuel into dry storage containers is being completed by Bruce Power. OPG is planning to establish dry storage facilities at the Darlington site by 2007.

All of 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 expects that all of 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 purposes of funding of nuclear fuel waste and decommissioning liabilities are that a deep geological disposal facility for used nuclear fuel will be available in 2025, 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 2034. In August 2000, OPG submitted a management plan to the CNSC entitled "Ontario Power Generation: Assumed Reference Plan for Used Nuclear Fuel Long-Term Management". This management plan proposed a revision to the reference date for an in-service used fuel disposal facility from 2025 to 2035. This plan has been further confirmed in communications between the CNSC and OPG in 2001 and now forms the basis for financial guarantees required for used fuel liabilities.

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. The CNSC issued an operating licence for the Bruce A station in 2000 based on, among other things, its review of this strategy. Financial guarantees required for these 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 described in the Ontario Nuclear Funds Agreement between the Province and OPG, which agreement is to become effective as of April 1, 1999 provided that the supplementary agreements for the custodianship and the management of the funds are entered into with the Province by September 2002. The key provisions of this agreement are: (i) for OPG to establish two segregated funds, comprising a used fuel fund (to fund future costs of nuclear used fuel waste management) and a decommissioning 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 approximately $2,344 million present value as at January 1, 1999 ($2,773 million as at December 31, 2001) of OPG’s low and intermediate level nuclear waste management and decommissioning liabilities; (iii) for a degree of risk sharing between OPG and the Province in relation to the cost of nuclear fuel waste 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 a guarantee fee equal to 0.5% of the amount guaranteed from time to time. The segregated funds will be administered by a third party and will be kept separate from OPG’s other assets. OPG will grant a security interest in both funds to the Province; as a result, the funds will not be available to satisfy the claims of OPG’s creditors.

The risk sharing arrangements under the Ontario Nuclear Funds Agreement with respect to the cost of long-term storage and disposal of used fuel are as follows (all are amounts 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. OPG will, however, be responsible for all incremental costs relating to the management of fuel bundles in excess of 2.23 million bundles. The Province is obligated under the agreement to make additional contributions to the used fuel fund if the fund earns less than a specified return over the Ontario consumer price index. The Province is entitled to any surplus in the fund including earnings in excess of the specified return.

OPG's required contributions to the segregated funds have been determined based on internally prepared reference plans, which are prepared with the assistance of external consultants and 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 as of December 31, 2001 are set out in the following table:

Present Value of Nuclear Waste Management and Decommissioning Cost Estimates

	Present Value December 31, 2001 (millions of dollars)
Incurred liability:	
Decommissioning	$2,556
Waste management	4,814
	7,370
Future liability(1)	358
Total liability	$7,728
Less: OEFC commitment	2,773
Less: OPG accumulated funds(2)	1,208
Net unfunded liability	$ 3,747

Notes:

(1) Represents estimated liabilities for nuclear waste that would be created at OPG's Pickering, Bruce and Darlington nuclear generating stations during their remaining planned operating lives based on financial reference plans.

(2) To be deposited in segregated funds pursuant to the Ontario Nuclear Funds Agreement.

Since April 1, 1999, OPG has been making contributions to a separate account pending the establishment of segregated funds. At the end of 2001, OPG had accumulated a net balance of approximately $1,200 million in this separate account. Once the segregated funds specified in the Ontario Nuclear Funds Agreement are established, funds from this separate account would be transferred to these segregated funds. This is expected to occur late in 2002. OPG will make an initial contribution to the decommissioning fund of approximately $500 million out of the approximately $1,200 million in the separate account. OPG expects, based on current estimates, that this amount, together with the OEFC contribution, will fully fund its obligations in respect of decommissioning liabilities. Any surplus in the decommissioning fund is shared between OPG and the Province on an equal basis; however, OPG is required to direct its share of any surplus into the used fuel fund.

The remaining funds from the separate account will be placed in the used fuel fund consistent with requirements of the Ontario Nuclear Funds Agreement. OPG will thereafter make quarterly payments to the used fuel fund calculated so that if paid over the assumed remaining life of OPG's nuclear stations, these payments, together with fund assets and earnings on accumulated funds, would fund the estimated cost of used fuel management. Based on the current reference plan, the annual contributions to the used fuel fund will be approximately $454 million for the period from 2002 to 2008 OPG's maximum contribution to the used fuel fund would be approximately $700 million annually if for the period from 2002 to 2008 OPG's liability reaches the maximum amount possible under the risk sharing thresholds established pursuant to the Ontario Nuclear Funds Agreement. However, if the investment income earned in the segregated funds becomes taxable, OPG's aggregate liability and these contributions would increase further. See "*Business of OPG – Relationship with the Province and Others – Stranded Debt, Proxy Taxes and Effect of Change in Ownership on Tax Status – Proxy Taxes*" and see "*Business of OPG – Risk Factors – Nuclear Operations*".

If the decommissioning fund ceases to be fully funded, OPG would be required to make quarterly payments to that fund calculated in a similar manner with reference to that fund's assets and earnings (including the OEFC commitment) and the estimated cost of decommissioning and low and intermediate level waste management based on the then current reference plan.

OPG's contributions to the segregated funds 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 currently applicable to the Corporation and certain of its subsidiaries by virtue of the Province's 100% ownership of the Corporation. In addition, investment income earned on these funds is treated by OPG as being exempt from proxy tax. If income earned on the funds is subject to tax, 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, Proxy*

Taxes and Effect of Change in Ownership on Tax Status – Proxy Taxes" and see "*Business of OPG – Risk Factors – Nuclear Operations*".

Changes to the estimated level of contribution to the funds will be dependent 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 or if the funds become subject to tax. OPG's contributions to the used fuel fund may not, however, decrease until the fund is 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.

Bill C-27, the legislation implementing the Federal Government's nuclear fuel waste management strategy, was passed by the House of Commons on February 26, 2002. It will come into force upon Royal Assent, which is expected in mid-2002 with the waste management organization contemplated by the legislation to be put in place shortly thereafter. This is a key part of the Government's strategy on nuclear fuel waste management. It requires owners of nuclear fuel waste to form a waste management organization that would report regularly to the Federal Government and would make recommendations on long-term management of nuclear fuel waste.

Bill C-27 also requires nuclear fuel waste owners to establish a trust fund to finance implementation of these recommendations. In this regard, OPG would be required to make an initial deposit of $500 million into a trust fund with a financial institution no later than ten days after the day on which Bill C-27 comes into force. Further, Bill C-27 would require that each year thereafter, OPG deposit an additional $100 million into this trust fund until an approach for long term used fuel management is approved. For purposes of the Ontario Nuclear Funds Agreement, this trust fund will form part of the used fuel segregated fund established under that Agreement, and deposits to the trust fund will be made from the used fuel segregated fund. Bill C-27 requires the waste management organization to submit, within three years of Bill C-27 coming into force, 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 would be submitted to the Federal Minister of Natural Resources who would make a recommendation to the Governor in Council. One of the approaches for the management of nuclear fuel waste shall be selected from among those set out in the study by the Governor in Council. Implementation requirements after selection of an approach are detailed in Bill C-27.

The CNSC can require 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.

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. Radioactive waste materials will be turned over to OPG during the term of the lease in accordance with nuclear waste agreements between the parties. The CNSC will require financial guarantees regarding the discharge of liabilities. Under the Ontario Nuclear Funds Agreement, OPG has arranged with the Province for any financial guarantee associated with these liabilities.

Human Resources

OPG currently has approximately 11,600 full-time employees and 650 contract staff. The majority of OPG's full-time employees are represented by two unions; approximately 6,900 by the Power Workers' Union (the "PWU") and approximately 3,350 by The Society of Energy Professionals (the "Society"). Approximately 50 employees are represented by the Security, Police and Fire Professionals of Canada. OPG's construction employees are represented primarily by 18 construction trade unions through the Electrical Power System Construction Association (the "EPSCA"). There are approximately 1,300 executive and managerial staff that are not represented by a union. As of December 31, 2001, OPG had approximately 12,000 full-time employees and 700 contract staff.

In January 2002, OPG announced a restructuring plan that will lead to a company-wide staff reduction of approximately 17%, representing about 2,000 positions. OPG expects the reductions to be achieved equally over each of the next two years. To the extent possible, a significant portion of the targeted downsizing will be achieved on a voluntary basis. Implementation plans that maximize voluntary reductions were developed in consultation with the PWU and the Society and approximately 1,200 of the positions targeted for downsizing have been achieved through voluntary means to date. 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 will be relocating to either the Sir Adam Beck facilities near Niagara Falls or to the Nanticoke Generating Station, located in Haldimand County. Based on current estimates, OPG expects the costs of the restructuring plan, including relocation costs, to be approximately $400 million. This restructuring will better align OPG's resources, improve its efficiency and effectiveness, and contribute to its future competitive positioning in the electricity market.

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 competitive marketplace. In September 2001, the PWU and OPG negotiated a four year agreement in order that there be 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. Over the past year, the number of grievances outstanding at year end has been reduced from more than 300 to approximately 200.

The Society and OPG 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. As such, the Society has never engaged in a work stoppage. The last PWU strike was in 1985 and lasted for 10 days. The parties quickly agreed to third party arbitration to resolve their issues. 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 have placed constraints on management's flexibility to operate its business.

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. The Partnership Agreement is also the framework within which the parties will work to manage new employment-related initiatives in OPG for the future. One of the successful outcomes of the Partnership Agreement was the negotiation of renewal collective agreements as noted above. OPG believes that recent negotiations with both the PWU and the Society reflect a material improvement in its relationships with these unions.

These improved relationships have also enabled OPG, the PWU and the Society to negotiate provisions in the collective agreements that facilitate the implementation of OPG's decontrol commitments. These provisions included the lease of the Bruce A and Bruce B stations in 2001 and the strategic reorganization or outsourcing of support services and non-core businesses, such as information services through the transfer of the operation and support of OPG's information services to New Horizon System Solutions Inc., as described under *"Business of OPG – Information Technology",* and the sale of OPG's interest in Kinectrics Inc. to AEA Technology plc. effective January 1, 2002, as described under "*Business of OPG – Research and Development*". In addition to these provisions, OPG's collective agreements contain enhanced provisions for the planning and redeployment of staff, and some collective agreements provide a process for the use of purchased services. Grievance resolution procedures in both the PWU and the Society collective agreements provide a streamlined process to handle complaints and help minimize the potential for grievance backlogs. The collective agreements with the Society provide an opportunity to tie compensation to performance and include a commitment to mediation and arbitration with no strikes or lockouts until 2005. The parties have agreed that, upon the completion of OPG's nuclear recovery plan, they will discuss whether or not to merge the non-nuclear and nuclear collective agreements.

Improved partnership between OPG and the unions is also reflected in the establishment of a corporate-wide goal-sharing program. This is a self-financing incentive plan that gives unionized employees a stake in OPG's financial success through the opportunity to share in earnings in excess of business plan targets. This incentive program, together with incentive opportunities for non-represented employees, means all OPG employees now have a financial stake in OPG's success. OPG believes that these plans have contributed significantly to improved employee understanding of the drivers of business success, and will continue to promote and foster innovation, flexibility and a continuous raising of the performance bar.

OPG also negotiates directly with two building trade unions in the construction sector, the Machinists and the Canadian Union of Skilled Workers. OPG negotiated renewal collective agreements with these two building trade unions also for the period from May 1, 2000 to April 30, 2004. OPG has also negotiated a collective agreement effective December 28, 2000 to January 1, 2003 with the Security, Police and Fire Professionals of Canada.

During the 2001 negotiations with the PWU, there were major changes 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 about 100. In addition, a large number of premium payments were reduced. In the PWU collective agreement for the non-nuclear business unit, management's flexibility to contract out work was enhanced, and employees covered by that agreement received an employment guarantee for the life of the agreement which expires on March 31, 2006. This collective agreement covers approximately 2,700 employees.

In addition to maintaining good business relations with OPG's unions, the human resources group plays an important role in supporting the achievement of corporate objectives by delivering programs that help prepare OPG for competition in the Ontario market after Open Access. Examples of activity in this area include 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 "*Business of OPG – Health and Safety– Occupational Health and Safety*".

Health and Safety

Occupational Health and Safety

OPG is committed to the safe operation of all its facilities and to workplace health and safety excellence. This commitment stems in part from the fact that OPG's historic health and safety record was suboptimal. OPG's goal is to achieve top tier wellness and conventional safety performance by 2003 compared to other similar electrical generation companies and utilities. Corporate performance measures for safety address accident severity and injury rates and are monitored quarterly and annually. Local safety measures are also required and safety targets are expected to be incorporated into the goal-sharing compensation program applicable to OPG's unionized employees. In 2000, OPG's conventional workplace safety performance improved significantly over 1999 and has improved again in 2001. Management and employee compensation is tied, in part, to success in achieving this goal.

OPG's conventional safety management system is being enhanced to conform with the British Standards Institute's Occupational Heath and Safety Assessment Series 18001 ("OHSAS 18001"), which is consistent with the ISO 14001 standard adopted for OPG's environmental management system. Standards and procedures are being updated throughout OPG in accordance with this model. In December 2001, the Niagara Plant Group was the first OPG location to receive a recommendation for registration according to the OHSAS 18001 specification document. Other hydroelectric, fossil and nuclear facilities are working towards implementation of this safety management system.

OPG's risk management process for its employees and contractors is integral to the safety management system. As part of this process, Joint Health and Safety Committees across OPG receive extensive training, including that leading to their certification under Provincial legislative requirements. Hazards have been identified throughout the organization and operational controls implemented to mitigate these risks in accordance with the *Occupational Health and Safety Act* (Ontario) and external and internal best practices. In addition, comprehensive radiation protection training and other programs have been developed to address risks associated with ionizing radiation in nuclear operations, as required by the *Nuclear Safety and Control Act* (Canada) and associated regulations.

OPG is establishing a workplace health management system. OPG has embarked upon a range of health support initiatives, including disability and attendance management, and a broad range of wellness support programs for employees and their families. Employee sick leave statistics are closely monitored as part of corporate performance measurement, and are linked to and supported by a state-of-the art disability management program. Attendance management programs are in place to encourage employees to adopt healthy lifestyles and to assist them with workplace issues and stress management through education and a variety of other activities.

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 "ALARA" (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 health physicists who have been certified by the CNSC. The certified 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. 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 and foodstuffs. 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.

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. Certain of the intellectual property assets transferred to OPG have, in turn, been licensed by the Corporation to Hydro One and the Electrical Safety Authority for use solely in connection with such parties' business; OPG has been granted corresponding licences as part of the reorganization. Licences of intellectual property assets among the Corporation, 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

Historically, most of OPG's non-nuclear research was conducted by its Ontario Power Technologies division ("OPT"), while most of the nuclear research and development was conducted at Atomic Energy of Canada Limited and at private sector facilities by the CANDU Owners Group. In August 2000, OPG transferred certain assets (including many patents) relating to its OPT division to Kinectrics Inc., a new independent science and engineering services company, in return for a 90% interest in Kinectrics Inc. The remaining 10% interest was owned by C-SAT Technologies Inc. ("C-SAT"), a consortium comprised of AEA Technology, plc and the partnership of Canatom NPM Inc. and Scientech Canada Inc. Effective January 1, 2002, OPG sold its 90% interest in Kinectrics to a Canadian subsidiary of AEA Technology plc. AEA Technology plc., formerly part of the United Kingdom Atomic Energy Authority, operates in 31 countries. OPG expects to continue as a significant customer of Kinectrics and has committed to make certain levels of purchases from Kinectrics in each of 2002, 2003 and 2004.

Supply Chain

In 2000, OPG joined 20 major U.S.-based energy sector companies in investing in The Pantellos Group, an e-commerce marketplace created to provide value-added services and solutions for its members' supply chain functions. Pantellos is currently expanding its operations into the European and Asia-Australia energy sectors. OPG anticipates that its investment and membership in the Pantellos marketplace will enable it to leverage a number of commercial opportunities offered by the company. These opportunities will allow OPG to realize supply chain process and price efficiencies and drive operational improvements and efficiencies through strategic partnering with and through Pantellos. In conjunction with this investment, OPG is investing in a number of process and technology improvements related to supply chain operations. These include development of an electronic catalogue that captures materials data, electronic links to suppliers that enhances process automation and implementation of a structured continuous improvement methodology that is supporting process efficiencies.

Venture Capital

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.'s strategy is to optimize financial returns by making equity investments in well-run private companies which have enabling or break-through technologies and who are at the advanced start-up or later stage of growth. OPG Ventures Inc. plans to invest up to $100 million over its initial three years of operation, and had invested $9 million as of December 31, 2001 and had $19 million in outstanding commitments, approximately half of which is expected to be invested in 2002. Included in the initial investments are companies developing technologies such as fibre optic power measurement and energy management.

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 developing 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. Construction of the project is expected to begin in the first half of 2002 and the plant is scheduled to be in-service in the spring of 2004. 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.

Information Technology

OPG's competitiveness depends in part on its ability to effectively implement best practices and leading edge information technology systems and operations. OPG is implementing and supporting the information technology systems necessary to manage the changes and new opportunities in Ontario's deregulated electricity market and the emerging North American energy markets. 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 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. ("BTS"), a wholly owned subsidiary of Cap Gemini Ernst & Young Canada Inc., to transfer the operation and support of OPG's information services to New Horizon System Solutions Inc. ("New Horizon"). Approximately 600 employees from OPG's Information Services Group transferred to New Horizon on February 1, 2001. Effective March 1, 2002, OPG sold its remaining 49% interest in New Horizon to BTS. 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 core business priorities. The divestiture also assists OPG in scaling its information technology resources appropriately as it implements measures to meet its decontrol commitments.

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 will provide e-commerce services for retail transaction management to market participants in the energy sector including utilities, retailers and other energy services providers. Services offered by The SPi Group are expected to remove barriers to entry and may also create other commercial opportunities.

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, due in part to the September 11, 2001 terrorist acts, the available coverage and limits may be less than the amount of insurance obtained in the past, and the recovery for losses due to terrorists acts may be limited. OPG is self-insured to the extent that any losses may exceed the amount of insurance maintained.

OPG purchases insurance coverage as required by statute, namely owned and leased automobile and nuclear liability. OPG believes 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. OPG has been advised by its nuclear liability insurers that it would be able to obtain nuclear liability insurance in respect of any increased coverage requirements. OPG expects that the incremental cost of such coverage would not have a material adverse effect on its business, results of operations, financial condition or prospects. See *"Business of OPG – Regulation – Nuclear Regulation".*

Relationship with the Province and Others

Provincial Authority

As a corporation governed by the *Business Corporations Act* (Ontario), the Corporation's management is supervised by its Board of Directors which is obligated 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.

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 Environment and Energy. The OEB consists of no fewer than five members appointed by the Province and various staff groups. The OEB is obligated to implement the Province's directives concerning general policy matters as well as those intended to address existing or potential abuses of market power by energy sector participants. See *"Business of OPG – Regulation – Ontario's Electricity Industry – Legislation".*

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*. 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 *"Business of OPG – Regulation – Ontario's Electricity Industry – The IMO".*

Transfer Orders and Indemnities

On April 1, 1999, pursuant to transfer orders made by Order in Council pursuant to the *Electricity Act 1998,* 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. Similar transfer orders were made on the same date in respect of the transfer of certain officers, employees, assets, liabilities, rights and obligations of Ontario Hydro to Hydro One, the IMO, Ontario Electricity Pension Services Corporation (a subsidiary of the OEFC that managed the Ontario Hydro pension plan on an interim basis until the assets and liabilities were transferred to OPG, Hydro One, the IMO and the Electrical Safety Authority) and the Electrical Safety Authority.

In consideration for the transfer of officers, employees, assets, liabilities, rights and obligations of the electricity generation business of Ontario Hydro, the Corporation issued to the OEFC notes payable in the aggregate principal amount of $8,526 million, including a note in the principal amount of $5,126 million (the "Equity Note"), and assumed a capital lease obligation of Ontario Hydro in the amount of $30 million on April 1, 1999. The Province has assumed all of the Corporation's obligations under the Equity Note and the OEFC has released the Corporation from its obligations thereunder. In connection therewith, the Corporation issued to the Province

256,300,010 common shares as fully paid and non-assessable shares. The OEFC has agreed that, without the consent of the Corporation, it will not sell the $3,400 million ($8,526 million less $5,126 million notes as at April 1, 1999) of notes of the Corporation held by it ($3,200 million as at December 31, 2001).

The transfer orders do not contain any representation or warranty from the Province or the OEFC with respect to the transferred assets, liabilities, rights and obligations. Under the *Electricity Act, 1998* and pursuant to the transfer orders, the OEFC was released from liability in respect of all assets and liabilities transferred by the transfer orders and is indemnified by transferees. However, the OEFC retained certain specific liabilities, as described in the transfer orders, including approximately $30,500 million aggregate principal amount of the former Ontario Hydro's publicly-held debt obligations.

Under the transfer orders, OPG is required to enter into certain agreements with various transferees, including agreements relating to: the administration of pension plans of the transferees; the liability for certain shared assets, rights, liabilities and obligations; the access to certain financial records and relevant personnel; long-term leases between OPG and Hydro One in respect of Hydro One's switchyards at each generating station and easements with respect to the equipment and installations of each of the parties at the generating stations; and agreements relating to the maintenance and operation of shared services and facilities.

OPG has 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; and the creation, treatment, payment to or from or other dealing with any equity account previously referred in the financial statements of Ontario Hydro, including certain litigation relating thereto. The indemnity specifically excludes: 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; 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); and any payment made or loss, expense or liability incurred by OPG as a result of the failure of a transfer order to transfer any interest of Ontario Hydro.

The indemnity ceases to be available to any of the Corporation's subsidiaries if the Corporation ceases to control them, unless the cessation of ownership results from the sale of the shares of a subsidiary in connection with the enforcement of security on such shares by an arm's-length creditor of OPG. The indemnity can be assigned under certain conditions with the consent of the Minister of Finance.

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.

OPG has indemnified the OEFC in respect of any claims, costs and expenses arising from matters relating to OPG's business and any failure by OPG to comply with its obligations to the OEFC under agreements dated as of April 1, 1999.

Relationship with the Province

Shareholder's 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 and other factors considered relevant by the Corporation's Board of Directors. In 2002, the Corporation currently expects to pay dividends on its common shares held by the Province equal to approximately (i) 35% of its net income; plus (ii) any portion of the proceeds of any decontrol transactions that are received by the Corporation and that the Corporation determines should be distributed to its shareholder. In 2001, the Corporation made dividend payments to the Province in the aggregate amount of $375 million. These payments are comprised of (i) quarterly dividend payments in the aggregate amount of $128.4 million; and (ii) two dividend payments of $123.3 million each, representing proceeds received by OPG from Bruce Power with respect to the decontrol of the Bruce facility. A further dividend of $123.4 million with respect to proceeds that have been received by OPG from Bruce Power was declared in December 2001 and was delivered to the Province in the first quarter of 2002.

Ontario Nuclear Funds Agreement

OPG and the Province have executed the Ontario Nuclear Funds Agreement, under which the Province has agreed to provide a degree of risk sharing with OPG in relation to certain used fuel management costs. See *"Business of OPG – Generation Operations – Nuclear Operations – Nuclear Waste Management and Decommissioning – Provisions for Future Nuclear-Related Costs"*.

Indemnities

The Province has provided an indemnity in favour of the Corporation and has guaranteed certain obligations of the OEFC to OPG under the indemnity agreements between OPG and the OEFC. See *"Business of OPG – Relationship with the Province and Others – Transfer Orders and Indemnities"*.

Consideration of Divestment by the Province

The Ministry of Finance and The Ontario SuperBuild Corporation have retained financial advisors to assist them in reviewing options for the divestment of all or a portion of OPG, including an initial public offering of equity of OPG or a sale of all or a portion of OPG's assets. The Ontario SuperBuild Corporation is an Ontario Crown corporation that was created to evaluate and make recommendations to the Province with respect to the appropriate private and public sector involvement in businesses and services that are currently owned or offered by the Province.

Stranded Debt, Proxy Taxes and Effect of Change in Ownership on Tax Status

Stranded Debt

One of the OEFC's purposes under the *Electricity Act, 1998* is to manage its outstanding liabilities, including "stranded debt". The *Electricity Act, 1998* 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. OPG has no obligations in connection with the stranded debt.

The *Electricity Act, 1998* provides for stranded debt to be paid over time by payments to be made to the OEFC by participants in the electricity sector including OPG, Hydro One and the local distribution companies. These payments include (i) proxy taxes in lieu of: (a) certain federal and provincial income taxes and capital taxes; and (b) municipal and school taxes; (ii) payments calculated using the graduated rates under the new gross revenue charge regime; and (iii) by certain amounts which may be payable by local distribution companies or municipal corporations to the OEFC on the transfer of their electricity business. The "residual stranded debt" is the portion of the stranded debt that cannot be paid by dedicated revenue streams. The Ministry of Finance has estimated the residual stranded debt to be $7,800 million as of April 1, 1999. The residual stranded debt will be paid over time by a debt retirement charge of 0.7 cents per kWh charged to all domestic load (except load supplied by generation that is directly connected to a distribution system or that is part of a consumer's facility and was in-service before October 1998), levied on electricity consumers. The *Electricity Act, 1998* provides the authority to make regulations regarding the determination of stranded debt and residual stranded debt, although these regulations have not yet been established.

Proxy Taxes

The Corporation and its Canadian subsidiaries are currently 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. Pursuant to the *Electricity Act, 1998*, however, the Corporation and these subsidiaries are each required to pay to the OEFC in respect of each taxation year an amount referred to as a "proxy tax" as long as they continue to be exempt from tax under the *Income Tax Act* (Canada) and *Corporations Tax Act* (Ontario). Proxy taxes are, in general, equal to the amount of tax the Corporation and its Canadian subsidiaries would otherwise be liable to pay under the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario) if it were not exempt. The Corporation and each of its Canadian subsidiaries will be required to calculate its income, taxable capital and other relevant amounts in accordance with the rules contained in the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario), as modified by the *Electricity Act, 1998* and related regulations. Under the regulations to the *Electricity Act, 1998*, the Corporation and its Canadian subsidiaries will be entitled to deduct, in computing income subject to proxy tax, the amount of contributions to a nuclear decommissioning fund or nuclear waste management fund. In addition, any related investment income earned on these funds is treated by OPG as being exempt from proxy tax. See *"Business of OPG – Effect of Change in Ownership on Tax Status" and "Business of OPG – Generation Operations – Nuclear Operations – Nuclear Waste Management and Decommissioning – Provisions for Future Nuclear-Related Costs"*.

Although the Corporation and its Canadian subsidiaries are exempt from tax under the *Income Tax Act* (Canada), they may also be ordered by the Lieutenant Governor in Council to pay to the OEFC such amount as may be specified, provided that no such payment may be required if it would impair the ability of the Corporation or such a subsidiary to meet its financial liabilities or obligations as they come due or to fulfil its contractual commitments.

The *Electricity Act, 1998* 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 assets each year. Part V of the *Electricity Act, 1998* governs the OEFC. After Part V is repealed, these payments shall be paid to the municipalities in the manner specified by the Minister of Finance, instead of to the OEFC. The payments in lieu of property taxes are equal to the difference between (i) the amount of property taxes for municipal and school purposes that the Corporation and its subsidiaries would have been required to pay in respect of land owned by them on which are situated generating station buildings and structures, if these assets were privately-owned and (ii) the amount of such taxes the Corporation and its subsidiaries actually pay to the municipalities on these assets determined on the basis prescribed by the *Electricity Act, 1998* regulations, for each square metre of inside ground floor area of the actual building or structure housing these assets. One of the purposes of the proxy tax and the requirement to pay the OEFC payments in lieu of property tax is to create a level playing field, from a tax perspective, for purposes of future competition between OPG and other generators seeking to sell electricity in the Ontario market.

The Corporation's hydroelectric generation subsidiaries, which previously were subject to the payments in lieu of property taxes described above, became subject to the new gross revenue charge regime that took effect on January 1, 2001 for all owners of Ontario based hydroelectric generating stations. Under this new tax regime, owners of Ontario based hydroelectric generating stations, including the Corporation's hydroelectric generation subsidiaries, no longer pay property taxes to municipalities on their generating station buildings and structures. They are only required to pay property tax to municipalities on their buildings and land not used in connection with the generation of electricity. See *"- Special Charges on Hydroelectric Generating Stations", "– Effect of Change in Ownership on Tax Status"* and *"Business of OPG – Generation Operations – Nuclear Operations – Nuclear Waste Management and Decommissioning – Provisions for Future Nuclear-Related Costs"*.

Effect of Change in Ownership on Tax Status

The current tax-exempt status of the Corporation and its Canadian subsidiaries under the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario) reflects the fact that the Corporation is wholly-owned by the Province of Ontario. This tax-exempt status might be lost in a number of circumstances, including if the Province of Ontario ceases to own 90% or more of the shares or capital of the Corporation, or if a non-government entity has rights immediately or in the future, either absolutely or contingently, to acquire more than 10% of the shares of the Corporation.

Under the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario), when a corporation ceases to be exempt from tax, its taxation year is deemed to have ended immediately before the corporation ceased to be exempt from tax and a new taxation year is deemed to have commenced immediately thereafter. Immediately before the end of such taxation year, such corporation is deemed to have disposed of each of its assets at their then fair market value and to have reacquired such assets at that amount for purposes of computing its income in the future as a taxable corporation.

Under the *Electricity Act, 1998*, the Corporation will in accordance with the proxy tax regime described under *–"Proxy Taxes"* pay a proxy tax (referred to as the "Exit Tax") on any income deemed to have been realized upon such deemed disposition of its assets at their then fair market value. The Exit Tax will be payable to the OEFC upon the filing of the corporation's proxy tax returns for the taxation year that is deemed to have ended immediately before the corporation ceased to be exempt from tax. The *Electricity Act, 1998* provides an exception from the timing of the Exit Tax calculation in circumstances where a corporation ceases to be exempt from tax under the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario) as a result of its initial public offering of its shares. In these circumstances, the Corporation may, with the consent of the Minister of Finance, determine the amount of Exit Tax prior to losing its tax-exempt status (i.e. prior to the time the shares are issued to the public). The amount determined must reasonably approximate the Exit Tax that would otherwise be payable and will be based upon an estimate of the future fair market value of the assets at the time the corporation ceases to be tax-exempt. Once the amount of the Exit Tax has been agreed to by the Minister of Finance, it cannot be varied or altered unless the Corporation made a misrepresentation attributable to neglect, carelessness or willful default or committed fraud in providing information used in estimating the Exit Tax amount.

In addition to the reacquisition of its assets at fair market value for purposes of computing its income in the future as a taxable corporation, the corporation is deemed to have claimed the maximum amount of reserves that it could claim had it otherwise been a taxable corporation at the time of its change in tax status. For purposes of certain provisions, the corporation is deemed to be a new corporation and, as a result, tax credits, tax losses and resource-based deductions not previously utilized by the corporation will not be available to it after the change in tax status. Essentially, the corporation is taxed as though it had a "fresh start" at the time of its change in tax status.

If there is such a change in the tax status of the Corporation or any of its exempt Canadian subsidiaries, it would, therefore, be subject to tax under the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario) and would no longer be subject to proxy taxes. The amount of taxes the Corporation would pay under the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario) may differ from proxy taxes that are currently imposed by the *Electricity Act, 1998*. The principal reason for such a change in tax liability would be the difference in the tax value of assets after such change in tax status from that which applied earlier. To the extent the fair market value of the Corporation's depreciable assets is greater than their undepreciated capital cost that is used for the purposes of calculating proxy tax payable at the time of change in tax status, its corporate tax liability will likely be reduced, as it will be eligible for higher capital cost allowance claims in the future. The opposite result would arise if the fair market value of the Corporation's depreciable assets should be less than their undepreciated capital cost as future claims for capital cost allowance would be reduced, resulting in a higher corporate tax liability. In addition, there can be no assurance that OPG's contributions in respect of the nuclear decommissioning or waste management funds would continue to be tax deductible in determining the tax liability of the Corporation nor that related investment income will continue to accumulate on a tax-free basis. These funds are described under *"Business of OPG - Effect of Change in Ownership on Tax Status"* and *"Business of OPG - Generation Operations - Nuclear Operations - Nuclear Waste Management and Decommissioning - Provisions for Future Nuclear-Related Costs"*. However, the Corporation has been engaged in discussions with the relevant taxation authorities to review various alternative structures or arrangements whereby such contributions would continue to be tax deductible.

Special Charges on Hydroelectric Generating Stations

Historically, hydroelectric generating stations paid water rental payments to the Province for the use of Crown lands based on both capacity and energy production. In 2000, the water rental payment regime was amended by the Province with payments based solely on energy production. This resulted in water rental payments increasing between \$3 million to \$4 million based on median production levels. In 2001, the Province introduced major tax reform for hydroelectric generating stations replacing historical municipal and school taxes levied on hydroelectric generating stations, water rental payments paid to the Province, and payments in lieu of property tax made to the OEFC on hydroelectric generating stations (see "- *Proxy Taxes*") with a new gross revenue charge (the "gross revenue charge").

Under this new gross revenue charge regime, the Corporation makes payments based on the gross revenue derived from the annual generation of electricity from its hydroelectric generating stations at graduated rates. The charges will be calculated on a station-by-station basis. The graduated portion of the gross revenue charge replaces the proxy property taxes and consists of four tiers of payments. The gross revenue arising from the first 50 gigawatt hours of annual generation from the generating station will be assessed at 2.5%. The gross revenue from the station's next 350 gigawatt hours will be assessed at 4.5%. The gross revenue from the next 300 gigawatt hours of annual production will be assessed at 6%, with the gross revenue arising from the station's generation above 700 gigawatt hours being assessed at 26.5%. The gross revenue charges arising from these graduated rates will be paid by the Corporation directly to the OEFC because one of the purposes of this new regime is to maintain the funding for the stranded debt. Since the municipal and school boards no longer receive property tax on land and buildings used in connection with the hydroelectric generating station, the Province will pay the municipalities and school boards directly for this loss in revenue. 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.

In addition to the graduated rates, the Corporation will pay an additional gross revenue charge of 9.5% on the gross revenue from the annual generation of electricity from those hydroelectric generating stations that are located on provincial Crown lands. This additional charge replaces the water rental charge under the old system and therefore will be paid by the Corporation directly to the Province. Of OPG's 69 hydroelectric generating stations, 49 are located on provincial Crown lands and are therefore subject to this additional 9.5% gross revenue charge.

Accordingly, the gross revenue charges payable will be dependent on both energy production and gross revenue, the calculation of which will be more precisely known when the Province releases the regulations that it is currently developing. The new gross revenue charge regime also proposes to provide an exemption from both the graduated rates and additional 9.5% charge for new, rebuilt or expanded hydroelectric generating stations, whereby the gross revenue resulting from the additional capacity will be exempt from gross revenue charges for a period of ten years.

In 2001, the gross revenue charges are estimated by OPG to total approximately \$307 million, using an assumed open market clearing price of \$40 per MWh in calculating the estimated gross revenue from each of its hydroelectric generating stations. In addition, in 2001, OPG paid approximately \$10 million in water rental payments to various agencies, including the Federal Government and the Province of Québec.

Regulation

Ontario's Electricity Industry

Legislation

The *Electricity Act, 1998* implements the fundamental principles of the restructuring of Ontario's electricity industry. These include the separation of the competitive components of the industry (generation and retail) from the monopolistic components 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 directives concerning general policy matters as well as those intended to address existing or potential abuses of market power by energy sector participants. 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, 1998* 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; and facilitate energy efficiency and the use of cleaner, more environmentally benign energy sources in a manner consistent with the policies of the Province. An additional purpose of the *Electricity Act, 1998* 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, 1998* 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 Minister and published by the IMO; and OPG's generation, wholesale and retail licences issued by the OEB. Elements of the restructuring of Ontario's electricity industry are largely in place, including the regulations and Market Rules that will 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. See *"Business of OPG – Risk Factors – Restructuring of Ontario's Electricity Industry"* and *"Government Regulation"*.

Open Access

The *Electricity Act, 1998* mandates non-discriminatory access to transmission and distribution facilities by providing 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. Unless exempted by regulation, contracts for the supply of electricity entered into by OPG prior to December 11, 1998 with substantially all of its customers ceased to have effect on May 1, 2002. See *"- Market Power Mitigation – Rebate Mechanism and Transitional Price"*.

For the first 18 months after May 1, 2002, there will be a uniform market-clearing price within Ontario calculated on a congestion-free basis. Settlements for generators and consumers will be based on metered energy multiplied by the uniform market price. If transmission constraints or line losses require less expensive generation to be removed from production and more expensive generation to start producing electricity, the constrained generators will be compensated by an additional payment which will be charged to consumers. During this initial 18 month period, the IMO will collect and publish 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 after this initial period. 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. Following market opening, interconnections with other jurisdictions are treated as separate zones from the rest of Ontario and separate zone prices will apply when an interconnection is constrained.

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 between suppliers and purchasers of electricity participating in the IMO wholesale market.

Under the *Electricity Act, 1998*, the IMO is authorized to make and enforce the Market Rules which are necessary to perform its function and administer the IMO controlled market. Each market participant is obliged to follow the Market Rules in accordance with its participation agreement with the IMO and its OEB licence.

Unless exempted by regulation or the Market Rules, all persons require authorization from the IMO to participate in the IMO-administered markets or cause or permit electricity to be conveyed into, through or out of the IMO-controlled grid. In addition, the IMO and all generators, transmitters, distributors, wholesale sellers, wholesale buyers and retailers have to obtain a licence from the OEB in order to participate in the Ontario electricity market.

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.

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 incorporated 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 could, 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 could 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. 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.

The IMO 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. For example, 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 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.

OEB's Licensing Process and Industry Codes

The OEB has developed licences for electricity generation, transmission, distribution, wholesaling and retailing. It has also developed several associated codes for retailing, transmission and distribution. The OEB issued a transitional generation licence to OPG that will remain in force until April 30, 2003. OPG has also received its wholesaler licence and retailer licence, which will remain in force until January 2006 and September 2005, respectively.

Market Power Mitigation

At April 30, 2002, OPG owned (excluding leased assets) approximately 73% of the generating supply options in Ontario. To address the possibility that OPG could exercise market power after the commencement of Open Access, the Province has 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 significant 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. At the end of each 12 month period following May 1, 2002, if the average spot market price as calculated under the framework exceeds 3.8 cents per kWh, OPG is required to pay a rebate 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. OPG will pay the rebate amount to the IMO and the IMO is responsible for allocating the rebate to all Ontario consumers on the basis of energy withdrawn from the IMO-controlled grid.

The 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 power pool at whatever price it chooses, as are competing generation companies. The rebate mechanism applies to OPG's production above 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. In 2002, 102 TWh would have been subject to the rebate mechanism had Open Access commenced in 2001. Based on the CRQ and approval of the corresponding CRQ reductions by the OEB, and assuming completion of the Lakeview, Lennox, Thunder Bay, Atikokan and Mississagi decontrol transactions and that the Bruce transaction qualifies as a decontrol transaction, OPG estimates that its CRQ would decrease by approximately 22.4 TWh in subsequent years, depending on when the decontrol transactions are completed.

In addition, the Province has 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 (being the Surplus Power, Real Time Pricing I, Real Time Pricing II and Load Retention and Expansion Price rate options) during a reference period from July 1, 1999 to June 30, 2000. 55 large power consumers with 83 sites are eligible for this transitional price relief, whose purchases during the review period accounted for approximately 5% of OPG's production in 2001. OPG is required to effectively offer for sale to these customers a volume of energy based on their consumption of special rate power during the reference period. Price is based on the average price paid by each customer during the reference period and is anticipated to be below market price. The maximum anticipated volume is approximately 5.4 TWh in the first year after May 1, 2002; 3.7 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, with the possibility that it will expire after only two years if certain decontrol targets are met by OPG.

Decontrol of Capacity

Another market power mitigation measure requires OPG to relinquish effective control of some of its generating capacity. This may be accomplished by OPG through various transactions and could be done in a variety of ways, including the outright sale or lease of power stations or by entering into other arrangements provided the result is that OPG transfers control of the timing, quantity and bidding of energy produced by OPG's power stations. OPG's decontrol targets are specified in terms of Tier 1 and Tier 2 capacity. "Tier 1" capacity is defined as all nuclear and hydroelectric generation in Ontario. "Tier 2" capacity is defined as that portion of Ontario's generation capacity, including fossil generation, inter-tie capacity and demand-side bidding, that is not part of Tier 1 capacity. At the end of 2001, OPG controlled an estimated 76% of Tier 1 capacity and 55% of Tier 2 capacity (both assuming

Pickering A is out of service). The foregoing percentages are based on the assumption that the Bruce transaction is a decontrol transaction approved by the OEB. Within 42 months after May 1, 2002, OPG would be required to reduce its share of in-service Tier 2 generating capacity through transfer of effective control of a minimum of 4,000 MW of in-service Tier 2 capacity. At OPG's discretion, it may substitute the transfer of effective control of up to 1,000 MW of hydroelectric power in place of an equivalent amount of Tier 2 capacity. Within 10 years after May 1, 2002, OPG must reduce its effective control of total Tier 1 and Tier 2 capacity to 35% or less of the supply options in the Ontario market.

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 of Tier 1 and/or Tier 2 capacity will not count towards OPG satisfying its 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, OPG has leased its Bruce A and B nuclear generating stations to Bruce Power in a transaction which closed on May 11, 2001. OPG is also pursuing further decontrol efforts having initiated an auction process for the sale of its Lennox, Lakeview, Thunder Bay and Atikokan fossil generating facilities as well as its hydroelectric plants on the Mississagi River system. On March 8, 2002, OPG announced it had reached agreement to sell its Mississagi hydroelectric plants to Brascan Corporation for $340 million. This transaction is expected to close in the second quarter of 2002. Subject to the successful outcome of the balance of the auction process, OPG's intention is to complete these transactions as soon as reasonably feasible. See *"Business of OPG – Generation Operations – Fossil Operations – Fossil Station Decontrol"* and *"- Nuclear Operations – Bruce 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 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 expand the existing Ontario-Québec inter-tie by 1,250 MW, scheduled to be constructed by 2004. In addition, Hydro One is completing the installation of three 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 up to 500 MW.

Operating Reserve

Under the market power mitigation conditions of its OEB licence, offers 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.

OEB Review

Forty-two months following May 1, 2002, the OEB will review and publicly report on OPG's success in attaining its decontrol target respecting Tier 2 capacity, as well as upon its plans for meeting its 10-year decontrol target. If the 42 month targets are met, the OEB will advise the Minister on the appropriateness and term of ongoing price controls over OPG's Tier 1 generation for the fifth through tenth years without altering the 10-year decontrol target. The OEB will conduct a further review in the seventh year following May 1, 2002 to determine OPG's progress in meeting its 10-year decontrol target. OPG will be required to file annual reports with the OEB in years five through nine following May 1, 2002 on its progress toward meeting this target.

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 because of the transboundary nature of discharges into the environment. See "*Business of OPG – 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") and the *Dangerous Goods Transportation Act* (which incorporates, by reference, the Federal *Transportation of Dangerous Goods Act Regulations*), 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 wastes), EPA Regulation 356 (ozone depleting substances or "ODS"), EPA Regulation 362 (polychlorinated biphenyls or "PCB" wastes), EPA Regulations 153/99 and 397/01 (which regulates 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 emission into the atmosphere of a number of other 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 are two outstanding orders issued by Ontario's Ministry of Environment and Energy pursuant to the EPA that require OPG to measure SO_2 and NO_x emissions and to determine whether there is contaminated property at the generating stations and to take remedial action, if necessary. See *"Business of OPG – 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 ODS and PCBs. The *Fisheries Act* 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* 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*, 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 and for dry storage at Bruce B and Pickering A, and one is currently underway at Darlington for its used fuel dry storage facility project. See "*Business of OPG – Generation Operations – Nuclear Operations – Nuclear Recovery Plan*".

Ontario's *Environmental Assessment Act* (the "EAA") traditionally required that only projects initiated by public bodies (which were listed in the regulations and included OPG) be assessed and approved under the EAA. Therefore, OPG was historically required to conduct full environmental assessments of all projects, including new developments or facility modifications, and obtain Ministry of Environment and Energy approval, unless otherwise exempted. Private sector companies were not subject to the EAA, except if a project was specifically designated for an environmental assessment. New regulations under the EAA 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.

Energy Regulation

The OEB Act, 1998 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 siting 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.

On April 11, 2002, Ontario Energy Trading International Corp. ("OETI") (a wholly-owned U.S. subsidiary of the Corporation) received authorization from FERC to sell electricity to wholesale customers in the United States at market based rates. This authorization does not limit the volume of transactions that OETI can enter into, nor does it contain any geographic limitations. In determining whether to issue a power marketer's licence, FERC considers whether the seller has adequately mitigated its generation market power in the United States and whether the seller or any of the seller's affiliates that own transmission facilities has adequately mitigated its transmission market power by providing, for example, open access transmission service consistent with FERC Orders Nos. 888 and 889. In approving OETI's FERC application, FERC has therefore determined, in part, that OPG is not affiliated with any entity that possesses market power over transmission in Ontario. This finding should, therefore, permit OPG as well as its subsidiary to purchase transmission services in the United States (with OPG currently being restricted to transactions at the international border because it does not have FERC authorization). OETI has also applied to the U.S. Department of Energy for an export permit. This permit will authorize OETI to export electricity from the United States into Canada. OPG anticipates that it will receive this export permit by the end of July 2002.

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 may only possess or dispose of nuclear substances and construct, operate and decommission its nuclear facilities in accordance with the terms of a CNSC licence. The licence specifies conditions which licensees must satisfy in order to maintain the right to operate nuclear facilities. 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 safety, with the CNSC setting safety objectives and auditing licensee's performance against the objectives. The regulations made under the NSC Act include provisions dealing with facilities' licence requirements, radiation protection, physical security for all nuclear generating stations and the transport of radioactive materials. The CNSC has also issued guidance documents to assist licensees in complying with regulatory requirements such as decommissioning, containment and shutdown systems for CANDU nuclear generating stations. Requirements spelled out in these guidance documents have been incorporated into the operating documents for OPG's nuclear generating stations.

The NSC Act is the product of a recent 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 decommissioning as a condition of granting a licence, order-making powers which are more flexible than those allowed under the predecessor legislation, the *Atomic Energy Control Act* and the right to impose higher monetary penalties than was allowed under such predecessor legislation. The NSC Act also grants the CNSC power to require nuclear operator re-certification and to set requirements for servicing licences and various nuclear facility security measures. The NSC Act also provides for increased emphasis on environmental matters, including a requirement that licensing 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 bans an operator from suing any person in respect of its liability under the legislation, except persons responsible for acts of sabotage.

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 *"Business of OPG – 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.

See also "- *Provisions for Nuclear-Related Costs*" for information about Bill C-27, the proposed Nuclear Fuel Waste Act.

Water Rights

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

The *Public Lands Act* (Ontario) grants jurisdiction to the Ministry of Natural Resources ("MNR") to regulate the management, sale and disposition of public lands and forests. OPG has water power leases, licences of occupation, land use permits and Crown leases for the purpose of generating electricity.

The *Lakes and Rivers Improvement Act* (Ontario) regulates the 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 construction and improvements of dams, water crossing drainage areas, channelling of a river and the covering of a length of a river.

International Rivers

Seven of OPG's hydroelectric generating stations are supplied by two major international waterways, the Niagara River/Welland Canal and the St. Lawrence River, and are subject to treaties with the United States relating to water use. Those stations represent approximately 45% of OPG's in-service hydroelectric capacity and approximately 54% of OPG's 2001 hydroelectric generation.

A 1909 treaty with the United States (the "Boundary Waters Treaty") governs the rights 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 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.

Each of these treaties grants Canada and the United States equal rights to use waters made available for power generation, subject to certain water use restrictions. 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 from the James Bay watershed to Lake Superior by the Ogoki and Long Lake Diversion in northern Ontario. Canada's rights and obligations under each treaty that relate to power generation on the Great Lakes and the St. Lawrence River are exercised by the Province, which has in turn granted certain of those rights to OPG under legislation 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 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 additional limits to ensure adequate flow over Niagara Falls for scenic purposes.

Niagara Region

Through a combination of statutory rights and a lease agreement with the Niagara Parks Commission that expires in 2056, 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 Canal. Together, these stations represent approximately 31% of OPG's in-service hydroelectric capacity and approximately 36% of OPG's 2001 hydroelectric generation.

Under a prior Niagara Parks Commission agreement which, subject to certain rights of the Province, expires in 2009, Canadian Niagara Power Company Limited ("CNP") is entitled to generate up to 74.6 MW as part of Canada's share of water under the Niagara Diversion Treaty. Under an agreement between OPG and CNP, OPG uses CNP's water at its higher head stations, returns to CNP the amount of energy to which it is entitled, and keeps the balance. This energy has accounted for an average of 3% of OPG's total hydroelectric generation over the past 10 years. OPG is currently negotiating with the Niagara Parks Commission and CNP regarding CNP's 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 is renewable to 2038.

St. Lawrence River

The R.H. Saunders station near Cornwall represents approximately 14% of OPG's in-service hydroelectric capacity and approximately 18% of OPG's hydroelectric generation in 2001. By statute, 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 12% of OPG's in-service hydroelectric capacity and approximately 14% of OPG's 2001 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 lease with the Province of Ontario that is renewable 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 on users in Manitoba and are subject to guidelines and directions provided by a board comprised of Ontario and Manitoba government representatives. These sites are included under "- *Interior Rivers"*.

Interior Rivers

58 of OPG's hydroelectric stations, representing approximately 43% of OPG's in-service hydroelectric capacity and 33% of OPG's hydroelectric generation in 2001, are located on 23 other Ontario river systems. OPG holds water power leases and licences with the Province on the river systems that supply 40 of these stations. These leases and licences have expiry or renewal dates 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 40 stations covered by these licences and leases represent approximately 41% of OPG's in-service hydroelectric capacity. Approximately 1% of OPG's in-service hydroelectric capacity comes from the remaining 18 stations.

OPG's use of Ontario's interior watersheds is constrained by restrictions contained in certain water power leases and licences of occupation. OPG also operates within voluntary guidelines 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.

Environmental Matters

Overview

OPG's activities involve risk of adverse consequences to the environment and are subject to extensive governmental regulation. See *"Business of OPG – Regulation – Environmental Regulation"* and *"Business of OPG – Risk Factors – 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.

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 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 in 1999/2000. 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 and Energy, 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 and Energy 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.

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

A number of government initiatives have been implemented or 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 legislation limits OPG's annual SO_2 and oxides of nitrogen ("NO_x") emissions, net of emission credits used, as indicated in the table below. In order to meet these regulatory requirements, OPG has implemented air management initiatives to monitor and reduce emissions from its fossil generating stations. See "*Business of the Corporation – Generation Operations – Fossil Operations – Air Emissions and Effective Generation Limits*".

The Province has enacted an emissions trading regulation that provides for the reduction of SO_2 and NOx emissions from the Ontario electricity sector over time and allows for the trading of emission allowances and emission reduction credits by participants in the electricity market and industrial sector. The regulation includes an Emission Trading Code which sets out the rules governing the creation, registry, reporting and trading of emission reduction credits and allowances.

Effective January 1, 2002, the limit on SO_2 emissions from OPG facilities has been reduced to 153.5 Gg annually for the period 2002 to 2003. Starting in 2004 this limit will apply to the Ontario electricity sector as a whole until 2006, and will be reduced to 127.0 Gg annually in 2007 and beyond. SO_2 credit use is limited to within 10% of the annual cap. Prior to 2002 OPG's aggregated SO_2 and NO_x emissions had been limited by the Province to 215 Gg annually and OPG's SO_2 emissions to 175 Gg annually.

NO_x emissions for the Ontario electricity sector are capped at 35 Gg annually from 2002 to 2006, and 27.0 Gg in 2007 and beyond. The emissions trading regulation reduced OPG's annual NO_X emission limit to 35.0 Gg in 2002 and 2003, decreasing to 25.0 Gg in 2004, 22.4 Gg in 2005, 21.1 Gg in 2006 and 17.0 Gg in 2007. NO_x credit use is limited to within 33% of the annual cap. Under the regulation, summarized in the following chart, the "Other Fossil Generation" caps apply to other generators in Ontario.

Ontario – Electricity Sector Caps for Net SO_2 and NO_x Emissions

	SO_2 Emissions (Gg)		NOx Emissions (Gg)			
Year	OPG Facilities	Total Ontario Electric Sector	Lakeview GS	Other OPG Facilities(1)	Other Fossil Generation(1)	Total Ontario Electricity Sector
2001	175.0			215.0 less SO_2		
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		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 caps for OPG's Atikokan, Lambton, Lennox, Nanticoke and Thunder Bay facilities are expressed on an aggregate basis.

(2) No annual NO_x emission limits. All stations must respect other environmental regulations (e.g. Certificates of Approval) under the EPA.

(3) As of May 1, 2005, NOx emissions from Lakeview will be part of the cap set for other fossil generation.

(4) OPG limit in 2007 is based on 15.5 Gg in Pollution Emission Management Area plus 1.5 Gg outside Pollution Emission Management Area as specified in O. Reg. 397/01.

The United States Environmental Protection Agency has announced plans (the "State implementation plans") to require further air emission reduction measures to be in place in 22 eastern States by 2004, including those states within OPG's potential marketing area. The Ontario regulations applicable to Ontario power plants are consistent with the requirements of the State implementation plans, although the emission reduction timelines contemplated by the Ontario regulations are somewhat different than those in the State implementation plans.

Canada has signed and ratified the Framework Convention on Climate Change and has signed but not yet ratified the Kyoto Protocol. These initiatives call for reductions in the emission of "greenhouse gases", such as CO_2. Prior to 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. However, future requirements to limit the discharge of CO_2 and other greenhouse gases are unknown and uncertain, and there is no assurance that such limits would not impose significant costs on fossil electricity generators such as OPG. See "*Business of OPG – Risk Factors – 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 set for each radionuclide.

OPG reports annually on the results of its radiological environmental monitoring programs at each nuclear generating station that estimate 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 Energy 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, including chlorofluorocarbons ("CFCs") and halons, are used in refrigeration systems and fire fighting systems and can damage the ozone layer if emitted to the atmosphere. The policy requires that emissions of CFCs from chillers be maintained at near zero and all CFCs are to be removed from chillers by December 31, 2015. CFCs are no longer used in mobile vehicle air conditioning systems. All halon fire extinguisher systems have been replaced at the generating stations, and all portable halon fire extinguishers have been removed from service. OPG does not anticipate any material expense in dealing with its remaining supply of ODS.

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.

OPG uses chlorine to control zebra mussels at some of its fossil stations. OPG is, however, exempt from the provincial regulatory limits in the power sector MISA Regulation relating to chlorine-induced toxicity from programs to control zebra mussels. This exemption is scheduled to expire in July 2002. OPG is conducting studies aimed at reducing or eliminating the use of chlorine in the control of zebra mussels at its facilities. Current cost estimates for dechlorination of effluent from fossil facilities are $15 million, in aggregate, including upgrades to the chlorination systems. This work is in progress and is expected to be completed in advance of July 2002.

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"*. The cost to achieve compliance with the MISA Regulation chlorine-toxicity requirements at the nuclear facilities when they become applicable to OPG in July 2002 is currently estimated at $8.0 million.

OPG has replaced the brass condensers at Pickering B nuclear station, which were a source of contamination from that station. The Pickering A nuclear condensers will be replaced before they are returned to service. The estimated cost of completing the condenser tube replacements at Pickering A is $38 million.

Underground and Aboveground Storage Tanks

OPG is in material compliance with regulatory requirements relating to underground and aboveground storage tanks. OPG monitors underground storage tanks for leaks and has implemented fuel handling procedures.

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 power 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 Environment and Energy. 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 five years have been met.

Since 1997, the number of high priority sites covered by the Order has been reduced from 50 to seven as of January 30, 2002. Reports on the extent of contamination and risk assessment for the remaining areas which warranted detailed investigation were submitted to the Ministry of Environment and Energy. These reports and the independent third party reviews required by the Order are being considered to determine remedial action. The remaining medium priority and all the low priority sites represent a lower concern and may not require detailed assessment or remediation. The need to formally assess these sites will be addressed at a later date.

One additional priority site not covered by the Order, Lake Gibson, is currently being assessed under a parallel voluntary program, which started prior to the Order. In addition, voluntary assessments at ten other facilities have been completed. OPG estimates the present value of assessment and remediation of the high priority contaminated sites (excluding Lake Gibson) is approximately $27 million over the next two years, and such amount is fully reserved in the OPG balance sheet. See "*Business of OPG – Regulation – Environmental Regulation*". Additional costs for demolition and site clean up, including assessment and remediation of facilities in Toronto at Kipling Avenue, Orde Street, and 700 University Avenue are estimated at $22 million.

Management of Wastes

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 1996, 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 at December 31, 2001, the amounts of PCBs at the fossil, nuclear and hydroelectric stations were 715 tonnes, 849 tonnes and six tonnes, respectively, consisting of in-service high-level PCB transformers and small amounts of PCB waste to be shipped for destruction.

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. Contaminated equipment that remains in-service consists of lighting ballasts, cables, bushings and capacitors. PCB wastes were removed from OPG's hydroelectric facilities for storage and/or destruction. There are approximately eight tonnes of PCBs remaining to be dealt with in connection with the hydroelectric facilities, at an estimated cost of $200,000.

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 and the currently-stored PCB waste for destruction by 2005, and replace this equipment, at a total cost of approximately $14.8 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, which the Alberta government has announced will remain open until at least the end of 2002.

Substantially all of the previously accumulated in-storage PCB waste from OPG's nuclear stations has been destroyed. The Pickering A nuclear station has in-service high-level PCB transformers. OPG plans to phase out these transformers as part of the Pickering A return to service project at an estimated cost of $6.5 million. There are no in-service PCBs or PCB wastes at the Darlington or Pickering B nuclear stations.

OPG's total projected cost for remaining PCB phase-out and equipment replacement at its fossil and hydroelectric stations and the Pickering A nuclear station is $20.8 million. Remaining costs of PCB phase-out and destruction, estimated at $6 million, are covered in the environment provision. The Bruce A station has in-service high-level PCB transformers, but the $36 million cost of dealing with these will be borne by Bruce Power during the time it operates those facilities.

Nuclear Waste Management and Decommissioning

OPG has adopted certain management practices and planning assumptions to satisfy its nuclear waste management and decommissioning obligations. See *"Business of OPG – Generation Operations – Nuclear Operations – Nuclear Waste Management and Decommissioning"* and *"Business of OPG – Risk Factors – 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. Investors should consider these risk factors with other information set forth in this Annual Information Form.

Restructuring of Ontario's Electricity Industry

The Province retains the overall power to regulate and further restructure Ontario's electricity industry. Ontario's electricity market has been open to competition since May 1, 2002 with the introduction of competition in both the wholesale and retail markets in Ontario. The regulatory authorities responsible for the structuring, development and operation of the new Ontario electricity market, the IMO and OEB, and many of the incumbent participants in the Ontario market, including OPG, have little or no operating experience in a competitive electricity marketplace. Accordingly, it is possible that further changes in the structure of the electricity industry may be necessitated based on the experience of regulatory authorities and market participants in the new competitive environment. These changes may be accomplished either through fundamental changes by the Province to the structure of the Ontario electricity industry, or through changes made by the IMO to the Market Rules. In addition, it is difficult to predict the effect of these changing market and regulatory conditions on OPG's business, results of operations, financial position or prospects.

In certain jurisdictions where the energy marketplace has been opened to competition, factors such as episodes of energy price volatility and supply shortages have prompted a re-examination of the market framework by governments, regulatory authorities and consumer groups. Political, regulatory and consumer responses to the competitive wholesale and retail electricity markets in Ontario, and the possible development of a trend toward re-regulation in the North American electricity industry, could impact OPG and the successful implementation of OPG's business strategies and have a material adverse effect on its business, results of operations, financial position or prospects.

Market Readiness and Corporate Governance

OPG's ability to operate effectively and competitively in the new deregulated environment after Open Access is dependent in large measure on the development of critical new information systems and the enhancement or development of certain business processes and operations, such as energy trading and associated risk management operations. The successful implementation and ongoing enhancement of these initiatives is dependent on a number of factors including: changes in the Market Rules; the availability of qualified personnel; the ability of OPG to integrate its new systems with existing OPG information systems and with those of other market participants, including the IMO; and the usual risks inherent in any complex information technology project. Delays in completing these systems or future system failures could have a material adverse effect on OPG's business, operating results, financial condition or prospects. See *"Human Resources"* and *"Business of OPG – Information Technology"*.

In addition, OPG has established internal corporate governance and reporting structures to manage the risks inherent in operating in the new market (see *"Business of OPG – Management of Commercial Risks"*). There is, however, a risk that these systems may not adequately manage all such risks.

Competition

Increased competition will result in the loss of market share, some of which will result from OPG's mandated decontrol of Ontario-based assets. For example, Bruce Power announced its intention to restart two of the four Bruce A nuclear units. OPG believes its ability to compete 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 – Ontario's New Electricity Market"*.

Market Prices

A significant portion of OPG's revenue is tied, either directly or indirectly, to the spot market price for electricity in Ontario. The price of wholesale electricity purchases may vary depending on, among other variables: the availability of generation and transmission systems, economic growth, seasonal and weather-based variations in electricity demand, the plans and activities of other market participants, the evolution of newly deregulated electricity markets, regulatory decisions in Ontario and neighbouring jurisdictions (including deregulation), the exchange rate for the Canadian dollar and wholesale market trading rules, mechanisms for maintaining adequate generation reserves, and the level of competition. Although OPG engages in trading of electricity and related contracts and risk management activities to mitigate these risks, there can be no assurance that these activities will fully offset OPG's market price exposure. Electricity prices have proven to be extremely volatile at certain times in certain markets. This volatility could have a material adverse effect on OPG's business, operating results, financial condition or prospects. See *"Business of OPG – Management of Commercial Risks"*.

To the extent that OPG has an unhedged commodity price risk, it is subject to the risk that the price of the underlying commodity will be significantly different than forecast. OPG utilises a risk measurement methodology that calculates the value at risk ("VAR") to measure OPG's unhedged commodity price risk. The VAR methodology utilises historical prices to estimate volatilities and correlations of prices assuming a 95% confidence interval and a one day holding period. The corporate VAR limit for OPG has been established at $15 million. Although OPG believes this methodology is conservative and should adequately protect OPG against the risk associated with OPG's unhedged commodity price risk, there is no assurance that this will be the case.

Market Power Mitigation/Decontrol

OPG is subject to certain market power mitigation targets relating to decontrol of generation capacity in Ontario. The fulfillment 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 in a transaction which closed in May 2001. OPG announced, after the lifting of the Province's moratorium on the sale of coal-fired generating plants, that it will complete the decontrol of its Lakeview, Lennox, Thunder Bay and Atikokan fossil generating facilities, as well as the hydroelectric plants on the Mississagi River system as close as reasonably feasible to Open Access. OPG has announced an agreement with Brascan Corporation to sell its Mississagi plants, which is expected to close in the second quarter of 2002, but due to factors such as difficult market conditions has advised it may take somewhat longer than first anticipated to finish the balance of these decontrol initiatives. The failure of OPG to obtain satisfactory terms in 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. In addition, the extent to which OPG will be able to retain the proceeds from such transactions is uncertain. Whether a transaction will qualify as a "decontrol" transaction for purposes of satisfying OPG's licence requirements is not determined by the OEB until after a transaction has closed. The OEB has not yet considered whether the Bruce Power transaction and the proposed sales of Lennox, Lakeview, Thunder Bay and Atikokan fossil generating facilities and OPG's hydroelectric plants on the Mississagi River system will qualify as decontrol transactions. Although OPG believes that these transactions will satisfy its decontrol obligations, there can be no assurance that the OEB will come to that determination. The Bruce Power and Mississagi hydroelectric transactions are not conditional on, and it is expected that future transactions will also not be conditional on OEB approval and therefore cannot be unwound even if they are determined by the OEB not to constitute decontrol transactions. Accordingly, it is possible that OPG may be required to dispose of additional production assets in order to satisfy its 10-year market power mitigation targets under its licence. See "*Background – Ontario's New Electricity Market – Market Power Mitigation"*.

OPG's revenue will be affected by a 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 a revenue cap of 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. The IMO will pass on this rebate to all Ontario electricity consumers. Accordingly, OPG's ability to maximize its revenue will be affected by the rebate mechanism. In the event that the OEB were to determine that the Bruce Transaction does not qualify as transfer of effective control of the output of the Bruce nuclear facility generating units, this would leave OPG with the Market Power Mitigation Framework (MPMF) rebate obligation but not the spot market revenues associated with Bruce generation. In the longer term, a negative outcome on meeting the decontrol test could require OPG to decontrol an additional 3,000 MW of production assets in order to meet the 10-year market power mitigation targets and, if it does not, it may have an adverse effect on OPG. See *"Business of OPG – Regulation – Ontario's Electricity Industry – Market Power Mitigation – Rebate Mechanism and Price Relief*".

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"*.

Nuclear Operations

OPG developed its current nuclear recovery plan in 1997 with a group of independent nuclear experts. Its successful implementation will depend on many factors, including: there not being unanticipated deficiencies in its nuclear operations or greater-than-anticipated deterioration to its nuclear generating assets; there not being 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. OPG had implemented various recovery initiatives in the 1990s which did not significantly improve its nuclear performance. These initiatives did not adequately identify the underlying causes of OPG's declining nuclear performance and generally lacked sufficient levels of planning, co-ordination, resources and accountability.

There can be no assurance that OPG will be able to fully implement its nuclear recovery plan, and even if implemented, that improvements to OPG's nuclear operating performance will be significant and sustainable. 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 would have a material adverse effect on OPG's business, operating results, financial condition or prospects. See *"Business of OPG – Generation Operations – Nuclear Operations – Generating Facilities – Pickering A Lay-Up and Restart"*.

The staged restart of the four units at OPG's Pickering A nuclear station, is a key corporate initiative and is expected to enhance OPG's competitive position. 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 is valid until June 30, 2003, (unless suspended, amended, revoked or replaced) and may be renewed. To the extent there are significant delays in the project or increases in costs, this could materially adversely affect OPG's business, operating results, financial condition and prospects.

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 capital expenditures for repairs or replacements in addition to those contemplated under its nuclear recovery plan. 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 *"Business of OPG – Generation Operations – Nuclear Operations – Generating Facilities"*.

Nuclear reactors outside of Ontario have 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 *"Business of OPG – 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 (such as the proposed Bill C-27, the *Nuclear Fuel Waste Act*) 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 *"Business of OPG –Regulation – Nuclear Regulation"*.

There is no facility for the permanent disposal of nuclear 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; 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.

OPG and the Province have entered into the Ontario Nuclear Funds Agreement, under which the Province provides a degree of risk sharing with OPG in relation to certain used fuel management costs. This agreement is to become effective as of April 1, 1999, provided that the supplementary agreements for the custodianship and management of the funds are entered into with the Province by September 2002. Under the principles of this agreement, OPG would continue 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. Risk sharing with the Province does not apply 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. There is no facility for the permanent disposal of nuclear waste currently in operation in Canada, nor has the CNSC licensed any such facility. 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 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 and concerns for low level emissions. Consultation programs and studies based on international practices and standards have been undertaken to address these concerns. See *"Business of OPG – Generation Operations – Nuclear Operations – Nuclear Waste Management and Decommissioning"* and *"– 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 contributions to the funds, and the requirements of the Ontario Nuclear Funds Agreement and the *Nuclear Fuel Waste Act*.

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 by virtue of the Province's 100% ownership of the Corporation. In addition, any related investment income earned on these funds is treated by OPG as being exempt from proxy tax. The fund that will be governed by Bill C-27 for the management of long term used fuel will be a trust fund that may be subject to taxation pursuant to section 104 of the *Income Tax Act* (Canada) on some or all investment income earned. The federal and provincial tax authorities are aware of this potential tax impact and have been discussing potential solutions which, if successful, would mean that such funds will not be subject to taxation. The other segregated funds OPG will establish under the Ontario Nuclear Funds Agreement may also be regarded as trusts for income tax purposes. The Province has advised it intends to pursue a ruling from CCRA to clarify the tax status of these funds, and to explore options to preserve their tax exempt status. There is no assurance there will be a positive outcome of these various initiatives, further, 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, see *"Relationship with the Province, Stranded Debt, Proxy Taxes and Effect of Change in Ownership on Tax Status"*. Nor is there assurance that the investment income earned on these funds would continue to be tax-exempt. If these contributions were not deductible in determining OPG's tax liability, OPG's annual tax liability would increase materially by approximately $140 million per year for the period 2002 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 2002 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. 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 whereby such contributions would continue to be tax-deductible and the related investment income earned on these funds would continue to be tax-exempt. See "*Business of OPG – Relationship with the Province and Others – Stranded Debt, Proxy Taxes and Effect of Change in Ownership on Tax Status"*.

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. 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, results of operations, financial position or prospects. See "*Business of OPG – Generation Operations – Nuclear Operations – Nuclear Fuel Procurement*".

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 new personnel with the skills required to implement new processes and systems and to develop new lines of business, such as financial risk management products, as OPG positions itself to function in a competitive market. 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, the selective catalytic reduction installations at OPG's Lambton and Nanticoke stations 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 28% of OPG's personnel eligible for retirement by 2006. 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. This risk has increased with the January 2002 corporate restructuring announcement that will see a reduction of approximately 1,000 employees in 2002 and approximately another 1,000 in 2003.

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. In addition, in implementing decontrol transactions, OPG will need to maintain core capabilities in essential areas and to maintain service levels during transition periods, while seeking to achieve optimum staffing allocations. To achieve these objectives, OPG has negotiated collective agreements with its two major unions which OPG believes will facilitate restructuring activities as it positions itself for the competitive market and aligns the design and size of its support organizations with staffing requirements following decontrol transactions. 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 *"Business of OPG – Human Resources"*.

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 and thereby influence decisions of the Corporation, including for example, financing, acquisition and disposition decisions, capital structure and dividend policy. 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.

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 common shares and the determination of the amount of payments to be made by the Corporation to the Province by way of dividends. There can be no assurance that OPG and the Province will be able to resolve any potential conflict on terms satisfactory to OPG.

The Province has the power to alter the proxy tax, the gross revenue charge or other taxes or similar charges imposed on OPG. There can be no assurance that the proxy tax or gross revenue tax regimes will not be amended or that additional charges will not be imposed.

In addition, as described under –"*Effect of Change in Ownership on Tax Status*, the Corporation will be required to pay proxy tax (the "Exit Tax") on any income arising from the deemed disposition of its assets upon losing its tax-exempt status. The amount of Exit Tax that will be payable by the Corporation should it ever lose its tax-exempt status cannot be definitively estimated at this time, but could well be very material.

The Ministry of Finance and The Ontario SuperBuild Corporation have retained financial advisors to assist them in reviewing options for the divestment of all or a portion of OPG, although the timing of any potential equity offering or sale of assets has not been announced. The outcome is uncertain and the potential impact on OPG could be material.

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 "*Business of OPG - Relationship with the Province and Others - Stranded Debt, Proxy Taxes and Effect of Change in Ownership on Tax Status - Effect of Change in Ownership on Tax Status*".

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.

Environmental Risks

OPG is subject to federal, provincial and municipal environmental, health and safety laws. 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 dismantlement, abandonment and restoration of generation facilities at the end of their useful lives. See "*Business of OPG – 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. 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.

In recent years, OPG has relied increasingly on fossil generation to compensate for declining nuclear generation and, starting in 1998, to replace nuclear generation that has been taken out of service as a result of the lay-up of the Pickering A and Bruce A stations under its nuclear recovery plan. OPG's inability to restore nuclear generation would require it to continue to rely upon its current high level of fossil generation.

The amount of electricity that OPG may produce at its fossil generating stations is constrained, in part, by provincial, 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 implementation and maintenance of an effective emission reduction credit trading regime in Ontario. The absence of such a regime or the imposition of further, more stringent, air emission limits could have a material adverse effect on OPG's business, operating results or financial condition. See "*Business of OPG – Fossil Operations – Air Emissions and Effective Generation Limits*".

Canadian and international proposals to further limit fossil emissions, if implemented, could have an adverse impact on the cost and amount of OPG's fossil generation.

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 mid-western 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 *"Business of OPG – Relationship with the Province and Others – Relationships with Ontario Hydro's Successors"*, "*Business of OPG – Markets and Customers – OPG's Markets – Interconnected Markets*" and "*– Interconnected Markets*".

Interconnected Markets

OPG's ability to penetrate interconnected markets will depend upon many external factors, including: the cost to transmit electricity to these markets; the price of electricity in these markets; the competitive actions of other generators and power marketers; the pace of deregulation in Ontario and pace and nature of deregulation in the interconnected markets; currency exchange rates; any new trade limitations; and costs to comply with environmental standards imposed in these markets. There can be no assurance that OPG will be able to compete successfully in the U.S. interconnected markets. OPG's inability to access or compete in these markets could have a material adverse effect on OPG's business, operating results, financial condition or prospects, particularly in the context of market power mitigation. See *"Business of OPG – Markets and Customers – OPG's Markets – Interconnected Markets"* and *"Business of OPG – Regulation – Energy Regulation"*.

Acquisition Opportunities

OPG's growth strategy includes the potential acquisition or development of additional power generating facilities in the U.S. interconnected market areas close to Ontario. OPG plans to consider opportunities to enter the energy business in one or more regional jurisdictions or elsewhere, directly or in business combinations with others. OPG's success in this process will depend on numerous factors including: the availability of cash generated by operations or financing from external sources to find such acquisitions; the price it pays for any assets or other investments; the continuation of the current regulatory and economic environment in the United States and Canada which has led to the divestiture of generating facilities; OPG's ability to identify and complete appropriate acquisition and development opportunities in a competitive environment on terms acceptable to its shareholder; and the ability of OPG's management to successfully manage new businesses in jurisdictions in which it has little experience. The North American power market is characterized by numerous strong and capable competitors, many of whom may have extensive and diversified developmental or operating experience and financial resources similar to or greater than OPG.

Fossil Fuel Supply

OPG's coal and gas-fired electricity production is dependent on a secure, reasonably priced supply of coal and natural gas. 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 price and availability can also be affected by numerous factors. Given the fuel mix of OPG's current fleet, the potential impact of gas 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 price 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 because of supply concerns could have a material adverse effect on OPG.

Hydroelectric Generation

Approximately 45% 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 and prospects. See "*Business of OPG – Regulation – Water Rights*".

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

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 could require OPG to incur significant expenditures of capital and other resources. The consequences of dam failures could have a material adverse effect on OPG's business, operating results, financial condition or prospects.

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 and may result in increased reliance on other sources of generation.

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 2000 overall electricity demand grew at an annual rate of about 1.6% on a weather normalized basis, but in 2001 it remained flat as a result of slow economic growth. OPG expects Ontario primary demand to grow at an average annual rate of 1.4% between 2001 and 2010.

Government Regulation

OPG's operations are subject to extensive government regulation that may change from time to time. Matters that are subject to regulation include: 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 are frequently changed and are subject to interpretation, OPG is unable to predict the ultimate cost of compliance with these requirements or their effect on operations. Some of OPG's operations are regulated by government agencies that exercise discretionary powers conferred by statute. Because the scope of such authority is uncertain and may be inconsistently applied, OPG is unable to predict the ultimate cost of compliance with these requirements or their effect on operations. See *"Business of OPG – Regulation"*.

Financing Requirements

OPG operates in a capital-intensive industry and its current capital expenditure program is larger than normal as a result of the costs associated with the return to service of the Pickering A nuclear station. OPG will need to incur significant amounts of debt and arrange for credit support for its capital expenditure programs, to refinance debt maturities as they come due and for other working capital and collateral requirements in connection with its energy trading business. OPG's debt to OEFC consists of $2,450 million aggregate principal amount of senior notes and $750 million aggregate principal amount of subordinated notes. These amounts will have to be repaid over the period from 2003 to 2011.

The Company has reached agreement with OEFC to defer the maturity date of the $200 million principal amount of the notes due in 2002 to December 29, 2004. The debt maturities due in the next five years are as follows: 2002: $0; 2003: $200 million; 2004: $500 million; 2005: $300 million and 2006: $300 million. See Note 7 to the Corporation's audited consolidated financial statements for the year ended December 31, 2001, which reflects debt maturity dates before the agreement was reached to defer the 2002 principal payments to 2004.

The Province has not guaranteed the Corporation’s current indebtedness and has advised OPG that it will not guarantee future debt financing. OPG believes that equity contributions from the Province, as sole shareholder of the Corporation, will not constitute a source of capital in the foreseeable future. Moreover, the Province has not announced any decision or plan to permit the Corporation to sell equity to the public or other investors.

OPG expects that cash from its operations, together with additional borrowings available to OPG under existing credit facilities along with the potential for a new public debt facility, should provide sufficient financial resources during 2002 and 2003 to satisfy its debt service requirements based on current levels of indebtedness, and to meet OPG’s currently anticipated capital and other expenditure requirements during that period. The success of a new public debt offering is dependant on access to the capital markets. These markets can be volatile and the merchant generation sector has recently experienced challenging market conditions. There can be no assurance of the level or cost of public financing that OPG could obtain.

OPG expects that its cash flow from generation operations in 2002 and 2003 will be negatively affected by lower generation capacity resulting from the implementation of decontrol initiatives in furtherance of OPG’s market power mitigation obligations and due to the expensing of a significant portion of the expenditures relating to the Pickering A return to service. Revenues from production of the Pickering A units, which OPG expects to begin final commissioning of the first of four units towards the end of 2002, are expected to partially offset these reductions in cash flow in 2003. However, there can be no assurance that OPG will not require additional financing to supplement cash from operations to provide sufficient financial resources to satisfy its debt service requirements and to meet currently anticipated capital and other expenditure requirements.

The Corporation’s ability to arrange sufficient debt financing on satisfactory terms could be affected by numerous factors, including: its results of operations and financial condition; conditions in the capital and bank credit markets; the ratings assigned to the Corporation’s debt securities; the regulatory environment in Ontario; general economic conditions; investor confidence in the Ontario electricity industry and the Corporation; investor concerns following a major accident at a nuclear installation anywhere in the world; and the success of OPG’s nuclear recovery plan. Any failure or inability on the part of the Corporation to access debt markets on satisfactory terms could have a material adverse effect on the Corporation’s business, results of operations, financial condition or prospects. See “*Business of OPG – Regulation*”.

Credit Risk

Credit risk is the risk of non-performance by contractual counterparties with respect to payment for services provided. A majority of OPG's revenues are derived from sales through the IMO-administered spot market. Participants in the IMO spot market must meet IMO-mandated standards for creditworthiness with the result that OPG's risk for these sales should be effectively managed. To the extent that the credit support provided by purchasers of power to the IMO is inadequate, however, all market participants are responsible for any shortfall in proportion to their market activity. Until OPG fulfills its decontrol mandate, OPG is the primary generator of electricity supplying the Ontario market and therefore assumes the majority of this risk. OPG is exposed to credit risk as a result of its other business activities, including the sale of derivative products to third parties.

Foreign Exchange and Interest Rate Risk

OPG’s foreign exchange risk exposure is attributable primarily to U.S. dollar-denominated transactions such as the purchase of fossil fuel and the purchase and sale of electricity in U.S. markets. OPG currently manages its exposure by periodically hedging portions of its U.S. dollar cash flows according to approved risk management policies. Interest rate exposure for OPG is limited by the fixed rates on its long-term debt. 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.

Liquidity Risk

OPG's ability to arrange debt financing and the costs of debt capital are dependent on a number of factors including: (i) general economic and capital market conditions; (ii) credit availability from banks and other financial institutions; (iii) its maintenance of acceptable credit ratings; (iv) its relationship with the Province as the sole shareholder of OPG; and (v) the status of electricity market deregulation in Ontario.

OPG has not yet accessed the public debt markets. Future financings, including public debt financing, may include terms that are more restrictive than those applicable to OPG's existing credit arrangements. The Corporation's credit lines include standard negative pledge and reporting requirements. Included in the Corporation's current credit agreement are additional covenants which could impact the liquidity of the Corporation whereby a potential event of default could occur if the Corporation's shareholder, the Province of Ontario, reduces its interest to less than 51% of the outstanding shares in the capital of the Corporation and if at the time of such change in control, the Corporation has a credit rating of less than BBB.

OPG's operates in a capital intensive business and its initiative to return its Pickering A station to service requires significant financial resources, the majority of which OPG expenses during the year in which they are incurred. Furthermore, any acquisition or development project may require access to substantial capital from outside sources. OPG may also require external financing to fund capital expenditures necessary to comply with air emission or other regulatory requirements.

With the deregulation of the electricity market in Ontario and elsewhere, OPG is engaged in energy trading activities whereby certain counterparties can request that OPG provide collateral to secure various contractual or statutory obligations of OPG. The amount of collateral that OPG must provide may increase if OPG's credit rating is downgraded. If a counterparty requests collateral or additional collateral from OPG and OPG does not provide the required collateral within the time frames specified in the underlying contract or statute, it may trigger an event of default, potentially accelerating the aggregate indebtedness owed by OPG under certain credit arrangements or other financing agreements.

OPG's liquidity risk is managed by OPG maintaining appropriate credit facilities to ensure that OPG has the ability to respond to requests for collateral and finance its business. OPG expects to be subject to restrictions on its ability to give collateral under customary negative pledge provisions of any public debt financing. Depending on OPG's performance and market conditions at the time, OPG may not be able to arrange for necessary financing on a timely basis or on terms that are acceptable to OPG.

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, which was filed on January 1, 2000. At that time, the plan was fully funded. The next funding valuation report must be filed no later than January 1, 2003.

The funded position of the OPG pension plan at any time is dependent on the value of the plan's assets and its calculated liabilities. If the pension fund has more than the maximum surplus permitted under the *Income Tax Act* (Canada), restrictions are imposed on the contributions by OPG. If a deficit exists at the time the valuation report is filed, OPG would be required by legislation to make additional contributions to fund the deficit according to legislative requirements. The contributions required to fund the plan in 2003 will depend on, and are highly sensitive to, the rate of return earned on the plan's investments during the remainder of 2002 and on interest rates at the end of 2002.

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

The following table sets forth selected consolidated financial data derived from the audited consolidated financial statements of the Corporation for the years ended December 31, 2001, December 31, 2000 and for the nine months ended December 31, 1999. The comparative consolidated financial data for the Corporation for the year ended December 31, 2000 and for the nine months ended December 31, 1999 have been restated to reflect a change in accounting policy for pension and other post-employment benefits adopted in 2001 and applied retroactive to April 1, 1999. In addition, the comparative consolidated financial data for the Corporation for the year ended December 31, 2000 has been restated to reflect a revision to other post employment benefits resulting from an assessment of the Corporation's claims history.

The selected consolidated financial data for periods prior to April 1, 1999 are derived from the audited consolidated financial statements of the Acquired Business as operated by Ontario Hydro. The financial data for periods prior to April 1, 1999 have been prepared through specific identification of assets, liabilities, revenues, and expenses related to the Acquired Business, and through an allocation of certain common financial statement accounts and items of Ontario Hydro among its successors. The historical results of operations as reflected in the selected financial data below may have been different if OPG actually had been a stand-alone corporation with its own management and capital structure rather than a business unit of Ontario Hydro, as at the dates and for the periods presented prior to April 1, 1999. Accordingly, the financial information for such periods may not be indicative of the Corporation's future financial performance.

The selected consolidated financial data for the pro forma year ended December 31, 1999 set out in the following table are derived from the Corporation's pro forma consolidated statements of income for the year ended December 31, 1999, (the “Pro Forma Statement of Income”), which assumes that OPG's purchase and assumption of assets and liabilities, employees, rights and obligations of the Acquired Business had been completed as of January 1, 1999 in respect of the pro forma consolidated statement of income for the year ended December 31, 1999.

(millions of dollars)	Acquired Business		Restated Pro Forma[1][2]		
	3 months ended March 31, 1999	Restated[1] 9 months ended December 31, 1999	Year ended December 31 1999	Restated[1] Year ended December 31, 2000	Year ended December 31, 2001
Income Statement Information[3]					
Revenues	1,769	4,338	5,795	5,978	6,239
Operating Expenses					
Operation, maintenance and administration	551	1,786	2,353	2,365	2,559
Fuel	335	816	1,116	1,271	1,259
Power purchased	45	153	198	180	879
Depreciation and amortization	385	573	765	764	810
Property and capital taxes	7	277	369	379	308
Restructuring costs	-	-	-	-	67
	1,323	3,605	4,801	4,959	5,882
Operating income	446	733	994	1,019	357
Interest expense	545	134	179	140	139
Income (loss) before income taxes	(99)	599	815	879	218
Income taxes[4]	-	(282)	(378)	(389)	(66)
Net income (loss)	(99)	317	437	490	152

(millions of dollars)	Restated[1] As at December 31, 1999	Restated[1] As at December 31, 2000	As at December 31, 2001
Balance Sheet Information[3]			
Assets			
Current	1,630	2,193	1,698
Fixed	12,902	12,932	12,981
Other	1,063	1,507	2,007
Total	15,595	16,632	16,686
Liabilities			
Current	1,149	1,760	1,723
Long-term debt	3,422	3,219	3,015
Nuclear waste management and asset removal	4,235	4,482	4,724
Other post-employment benefits	960	1,032	924
Deferred Revenue	-	-	215
Other	421	446	615
Shareholder's Equity			
Common shares	5,126	5,126	5,126
Retained earnings	282	567	344
Total	15,595	16,632	16,686

Quarterly Financial Information

(Unaudited, in millions unless otherwise stated)

	Fiscal 2001 Restated Quarter Ended[(1)] December 31	September 30	June 30	March 31
Revenue	$ 1,558	$ 1,635	$ 1,507	$ 1,539
Net Income	$ (48)	$ 81	$ 17	$ 102
Basic and fully diluted earnings per common share*	$ (0.19)	$ 0.32	$ 0.07	$ 0.40
Dividends	$ 137	$ 138	$ 14	$ 86
Cash dividends declared per share*	$ 0.54	$ 0.54	$ 0.06	$ 0.33
Special dividend declared per share*	$ 0.48	$ 0.48	$ -	-

	Fiscal 2000 Restated Quarter Ended[(1)] December 31	September 30	June 30	March 31
Revenue	$ 1,526	$ 1,568	$ 1,399	$ 1,485
Net Income	$ 33	$ 169	$ 130	$ 158
Basic and fully diluted earnings per common share*	$ 0.13	$ 0.66	$ 0.51	$ 0.62
Dividends	$ 42	$ 42	$ 42	$ 79
Cash dividends declared per share*	$ 0.16	$ 0.16	$ 0.16	$ 0.31

* Per share amounts are in dollars and rounded to the nearest cent

Operating Information	Year Ended December 31 1996	1997	1998	1999	2000	2001
Net generated energy (TWh)[(5)]						
Hydroelectric	37.6	36.4	31.9	33.6	34.0	33.7
Fossil	19.0	24.4	34.2	36.1	42.4	40.2
Nuclear	77.8	70.3	59.9	61.4	59.8	47.7
	134.4	131.1	126.0	131.1	136.2	121.6
Total electricity purchased (TWh) (excluding Energy Banking)	1.4	3.4	5.0	5.1	3.3	19.1
Generating facilities net capacity factor[(6)](%)						
Hydroelectric	60	58	50	53	54	53
Fossil (coal only)	29	37	52	51	62	56
Nuclear	66	61	76	81	78	81
Generating facilities capability factor[(7)](%)						
Hydroelectric	91	89	90	91	92	93
Fossil (total)	69	62	67	68	76	71
Nuclear	68	62	77	81	79	82
Electricity sales volume (TWh)						
Ontario energy sales	129.6	128.0	128.7	132.4	135.8	136.6
Interconnected market sales	6.1	6.4	3.0	4.5	4.0	3.6
Total energy sales[(8)]	135.7	134.4	131.7	136.9	139.8	140.2
Ontario market share[(9)] (%)	90%	88%	87%	88%	89%	89%

Notes:

(1) In 2001, OPG changed its policy of accounting for changes in the net actuarial gain or loss for pension and Other Post Employment Benefits ("OPEB"), effective April 1, 1999. As a result of this change, the operating results for 2000 have been restated to reflect an increase in employee benefit expenses of $147 million, a decrease in net income of $95 million, and a decrease in retained earnings of $104 million. The restatement of operating results for 1999 resulted in an increase in employee benefit expenses of $16 million and a $9 million decrease in net income and retained earnings for the year ended December 31, 1999. In addition, an assessment of OPG's claims history for OPEB resulted in an increase to OPEB expense for 2000 of $32 million and a $20 million decrease in net income and retained earnings for the year ended December 31, 2000. The revision was accounted for retroactive to January 1, 2000.

(2) Assumes the purchase and assumption by OPG of the assets, liabilities, employees, rights and obligations of the Acquired Business had occurred on January 1, 1999 for the year ended December 31, 1999. In consideration for this transfer, the Corporation issued to the OEFC notes payable in the aggregate principal amount of $8,526 million, including a note in the principal amount of $5,126 million (the "Equity Note") and assumed a capital lease obligation of Ontario Hydro in the amount of $30 million. The Province has assumed all of the Corporation's obligations under the Equity Note and the OEFC has released the Corporation from its obligations thereunder, and in connection therewith, the Corporation issued to the Province 256,300,010 fully paid and non-assessable common shares. The pro forma adjustments are calculated after giving effect to the purchase.

(3) The audited financial statements of the Acquired Business as operated by Ontario Hydro for the three-month period ended March 31, 1999 reflect the historical book values and costs of the assets and liabilities as originally recorded by Ontario Hydro. The audited consolidated financial statements of the Corporation for the years ended December 31, 2001 and 2000 and for the nine months ended December 31, 1999 reflect the acquisition of the Acquired Business on April 1, 1999 at its fair value.

(4) As of April 1, 1999, the Corporation and certain of its Canadian subsidiaries are responsible for making payments in lieu of taxes (referred to as proxy taxes) to the Province. These payments together are calculated in accordance with the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario) and regulations made under the *Electricity Act, 1998*. The Corporation is also required to make payments in lieu of property taxes on its generating assets to the OEFC. These payments, together with property taxes and a gross revenue charge, are intended to approximate the total property tax paid by privately-owned companies. The gross revenue charge was introduced by the Province effective January 1, 2001 to restructure the payment of municipal property taxes, water rentals and payments in lieu of property taxes from OPG's hydroelectric generating facilities. The Corporation and certain of its subsidiaries are also responsible for making payments to the Province in lieu of property and school taxes on its generating assets. See " *Business of OPG - Relationship with the Province and Others – Stranded Debt, Proxy Taxes and Effect of Change in Ownership on Tax Status*".

(5) From April 1, 1999 to April 30, 2002, payments from wholesale customers were made to OPG and held by OPG in a notional account. These funds were then allocated among the successors of Ontario Hydro under the terms of revenue allocation arrangements that were established effective April 1, 1999, as follows: (i) the Electrical Safety Authority received a payment in 1999 for its start up costs, but received no further payments; (ii) Hydro One and the IMO received payments that were calculated on the basis of OEB-approved revenue requirements; (iii) OPG received fixed payments that were calculated by multiplying four cents times the forecasted energy OPG supplied to meet Ontario consumption for the year, expressed in kWh; (iv) OPG also received payment for ancillary services provided by it to the IMO; (v) the OEFC received a payment for the cost it incurs with respect to power purchase agreements (inherited from Ontario Hydro) between it and non-utility generators; and (vi) the OEFC also received an allocation equal to the residual amount in the notional account after all of the above allocations were made based on forecasted Ontario consumption and forecasted supply by OPG. Variations from the forecast in actual revenue delivered to the notional account, mainly as a result of differences between actual and forecast consumption and customer mix, were the responsibility of OPG and therefore impacted OPG's revenue.

(6) Net energy is the energy produced at the stations less energy consumed by the stations.

(7) Net capacity factor is an operational statistic which is determined for a period of time, usually one year. The capacity factor is the amount of electricity actually produced in the period as a percentage of its maximum production capacity.

(8) Net capability factor is the amount of electricity capable of being produced by a generating unit as a percentage of its maximum output, assuming no external constraints such as transmission limitations.

(9) Total energy sales may differ from the sum of total electricity generated and total electricity purchased due to the existence of an electricity banking arrangement with Hydro Québec.

(10) Market share is based on the Corporation's total volume of electricity sales in Ontario as a percentage of total Ontario sales volume from all suppliers of electricity.

Share Capital and Sole Shareholder

The authorized share capital of the Corporation consists of an unlimited number of common shares. As of April 30, 2002, 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's 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 2001 Annual Report of the Corporation is incorporated herein by reference.

ITEM 6 - MARKET FOR SECURITIES

As at April 30, 2002, 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 of the Corporation.

Name and Municipality of Residence	Position with the Corporation and Period of Service on Board	Principal Occupation
WILLIAM A. FARLINGER(1) (2) (3)(4)(5) .... Toronto, Ontario	Director and Chairman of the Board of Directors since December 1998	Chairman of the Board of Directors
JALYNN H. BENNETT(2)(3) .... Toronto, Ontario	Director since December 1998	President, Jalynn H. Bennett & Associates Limited (a consulting firm)
DANIEL J. BRANDA(2) (3) .... Oakville, Ontario	Director, resigned August 2001	President, INTRIA-HP (an electronic commerce company)
GRAHAM A. BROWN(7) .... Toronto, Ontario	Director and Chief Operating Officer since October 2000	Chief Operating Officer
O. MARK DE MICHELE (4) .... Coronado, California	Director since July 1999	Chairman and Chief Executive Officer, Urban Realty Partners L.P. (a real estate limited partnership)
PAUL V. GODFREY(1)(4) .... Toronto, Ontario	Director since December 1998	President and Chief Executive Officer, Toronto Blue Jays Baseball Club (a professional sports team)
DAVID W. KERR(2)(3) .... Toronto, Ontario	Director since December 1998	Chairman and Chief Executive Officer, Noranda Inc. (a natural resource company)
L. JACQUES MÉNARD Montréal, Québec	Director since April 2002	Chairman, BMO Nesbitt Burns, Toronto, and President, Bank of Montréal Group of Companies, Québec
RONALD W. OSBORNE(6) .... Toronto, Ontario	Director, President and Chief Executive Officer since December 1998	President and Chief Executive Officer
BRIAN A. ROBBINS(2)(3)(4) .... Aurora, Ontario	Director since December 1998	President and Chief Executive Officer, Exco Technologies Limited (a manufacturing company)
ARTHUR R. SAWCHUK(1)(4) .... Toronto, Ontario	Director since December 1998	Chairman of the Board of Directors, Manulife Financial Corp. (an insurance company)
RICHARD M. THOMSON(2) .... Toronto, Ontario	Director since December 1998	Retired Chairman and Chief Executive Officer, The Toronto Dominion Bank (a Canadian chartered bank)

Name and Municipality of Residence	Position with the Corporation and Period of Service on Board	Principal Occupation
LYNTON (RED) WILSON[(1)] Oakville, Ontario	Director since December 1998; retired April 2002	Chairman of the Board, Nortel Networks Inc. (an electronic commerce company) and Chairman of the Board, CAE Inc. (an aerospace engineering company)
WAYNE M. BINGHAM Aurora, Ontario	Executive Vice-President and Chief Financial Officer	Executive Vice-President and Chief Financial Officer
RICHARD DICERNI Mississauga, Ontario	Executive Vice-President and Corporate Secretary	Executive Vice-President and Corporate Secretary
DAVID W. DRINKWATER Toronto, Ontario	Executive Vice-President – Corporate Development and Legal Affairs	Executive Vice-President –Corporate Development and Legal Affairs
JOHN D. MURPHY Pickering, Ontario	Executive Vice-President – Human Resources and Chief Ethics Officer	Executive Vice-President – Human Resources and Chief Ethics Officer
EUGENE PRESTON Aurora, Ontario	Executive Vice-President and Chief Nuclear Officer	Executive Vice-President and Chief Nuclear Officer
BRUCE BOLAND Etobicoke, Ontario	Senior Vice-President – OPG Customer Solutions	Senior Vice-President – Customer Solutions
JAMES R. BURPEE Toronto, Ontario	Senior Vice-President – Pickering A	Senior Vice-President – Pickering A
PIERRE CHARLEBOIS Pickering, Ontario	Nuclear Chief Operating Officer (Acting) and Senior Vice-President – Technical Services and Chief Nuclear Engineer	Senior Vice-President – Technical Services and Chief Nuclear Engineer
JAMES (JIM) PATRICK TWOMEY Toronto, Ontario	Senior Vice-President – Electricity Production	Senior Vice-President – Electricity Production
S. SNICK MEYERS Oakville, 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 B	Senior Vice-President – Pickering B
DOMINIC IAFRATE Oshawa, Ontario	Senior Vice-President (Acting) – Darlington	Senior Vice-President (Acting) – Darlington
GISELLE S. BRANGET Toronto, Ontario	Vice-President and Treasurer	Vice-President and Treasurer
ADÈLE S. MALO Toronto, Ontario	Vice-President and General Counsel	Vice-President Law and General Counsel

Notes:

(1) Member of the Human Resources and Corporate Governance Committee.

(2) Member of the Audit Committee.

(3) Member of the Environment, Health and Safety Committee.

(4) Member of the Nuclear Review Committee.

(5) Mr. Farlinger has been a director of Laidlaw Inc. since 1994. Laidlaw Inc. filed voluntary petitions to reorganize under Chapter 11 of the U.S *Bankruptcy Code* and under the *Companies Creditors' Arrangement Act* in Canada on June 29, 2001.

(6) Attends all committee meetings but is not a member of these committees.

(7) May attend Audit, Nuclear Review and Environment, Health and Safety Committee meetings but is not a member of these committees.

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:

Ronald W. Osborne was President and Chief Executive Officer of Bell Canada (a Canadian telecommunications company) from 1997 to March 1998, President of BCE Inc. (a global telecommunications company) from 1996 to 1997, Executive Vice-President and Chief Financial Officer of BCE Inc. from 1995 to 1996;

Graham A. Brown joined the Corporation in October 2000. Previous to this, he served as Chief Operating Officer of National Power, plc (a U.K.-based electricity generator and retailer) from 1999 to September 2000, prior to which he served as its U.K. managing director from 1998 to 1999, commercial director from 1994 to 1998, and as a director from 1996;

Daniel J. Branda was President and Chief Executive Officer of Hewlett-Packard Canada, Ltd. (a computer company) from 1993 to 1998 and its Chairman from 1997 to 1998;

O. Mark De Michele was President and Chief Executive Officer of Arizona Public Service Company (an electrical power utility) from 1988 to 1997;

Paul V. Godfrey was President and Chief Executive Officer of Sun Media Corporation (a communications and media company) from 1996 to June 2000, and President and Chief Executive Officer of the Toronto Sun Publishing Corporation (a newspaper publishing company) from 1992 to 1996;

David W. Kerr was President and Chief Executive Officer of Noranda Inc. from November 1997 to 2001, and Chairman and Chief Executive Officer of Noranda Inc. (an international mining and metals company) from April 1995 to November 1997;

L. Jacques Ménard was Chairman of Hydro-Québec from 1996 to 2001;

Arthur R. Sawchuk was Chief Executive Officer of Avenor Inc. (a natural resource company) from November 1997 to July 1998 and Chairman, President and Chief Executive Officer of DuPont Canada Inc. (a diversified industrial company) from 1995 to 1997;

Lynton (Red) Wilson was Chairman of the Board of BCE Inc. from 1998 to May 2000, Chairman and Chief Executive Officer of BCE Inc. from 1996 to 1998 and Chairman, President and Chief Executive Officer of BCE Inc. prior to 1996;

Wayne M. Bingham was Senior Vice-President – Finance of Union Gas Limited (a natural gas storage, transportation and distribution company) from 1998 to March 1999, and Vice-President – Finance of Westcoast Energy Inc. (an energy company) prior to 1998;

Richard Dicerni was Senior Vice-President, Corporate and Environmental Affairs and Corporate Secretary of the Corporation from December 1998 to December 1999. Prior to that, he was Senior Vice-President, Corporate and Environmental Affairs, with Ontario Hydro from December 1997 to November 1998. Mr. Dicerni served as President and Chief Executive Officer of the Canadian Newspaper Association (a trade and lobbying organization) from 1996 to December 1997 and held several Deputy Minister positions with the Province from 1992 to 1996, including Deputy Minister of Education and Training and Deputy Minister of Intergovernmental Affairs from 1995 to October 1996;

David W. Drinkwater was Special Advisor to the Chairman and Chief Executive Officer of Bell Canada during 1998, Group Vice-President, Law and General Counsel of Bell Canada from 1996 to 1998 and, prior to that, a partner of Osler, Hoskin & Harcourt (a law firm);

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 also appointed to the position of Chief Ethics Officer on March 5, 2002;

Eugene Preston held various positions with the Corporation from January 1997 to December 1999, including Vice-President of Operations, Maintenance and Training and Senior Vice-President – Nuclear Asset Optimization Program. He was Plant Manager of Tennessee Valley Authority's Browns Ferry Nuclear Plant prior to January 1997;

Bruce Boland was Senior Vice-President, Energy Markets from March 2000 – 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;

James R. Burpee was Senior Vice-President, Electricity Production from October 1998 to February 2001, General Manager – Fossil from September 1997 to October 1998, and Site Vice-President – Bruce Nuclear Plant from September 1996 to August 1997;

Pierre Charlebois 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. Prior to 1996, Mr. Charlebois was Technical Manager, Production Manager and Plant Director at Pickering Nuclear Generating Station;

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;

S. Snick Meyers was President of DTE Energy Trading, a subsidiary of Detroit Edison, from 1996 to August 2001. From 1993 to 1996 Mr. Meyers was Director of Trading, Entergy Power Marketing;

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 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;

Dominic Iafrate held various positions with the Corporation at the Darlington Nuclear Station including Site Vice-President (Acting) from November 1999 to February 2002; Director, Operations and Maintenance from 1999 to November 2000, Site Support from 1998 to 1999; and Unit Manager from 1993 to 1998;

Giselle S. Branget was Vice-President and Chief Financial Officer of Integrex, a service-based subsidiary of Owens Corning Corporation (a manufacturing company) from May 1999 to March 2000. Prior to that, Ms. Branget was Vice-President of Strategic Planning and Corporate Development of Owens Corning Corporation, responsible for various finance, strategy and corporate development initiatives, 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. Ms. Branget was Treasurer of John Labatt Limited (a brewing, broadcasting and entertainment company) prior to May 1996; and

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 2000. Prior to that, Ms. Malo was corporate counsel to The Oshawa Group Limited (a wholesale and retail grocery distribution company).

Each director is elected annually to serve for a one year term or until his or her successor is elected or appointed except for Mr. William Farlinger who was elected Chair of the Board of Directors for a term to end at the close of the sixth annual meeting of shareholders being approximately May 2005.

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.

Human Resources and Corporate Governance Committee. The Human Resources and Corporate Governance Committee's mandate includes recommending nominations to the Board of Directors. The Committee also advises the Board of Directors on the Corporation's objectives and policies concerning the recruitment, development, placement and promotion of management as well as remuneration. The Committee is also charged with reviewing the terms of reference of Board committees, and ensuring compliance with corporate governance reporting requirements. The Committee is also responsible for reviewing pension plan and executive and management compensation arrangements.

Environment, Health and Safety Committee. The Environment, Health and Safety Committee oversees the Corporation's environment, health and safety policies to ensure compliance with applicable legislative and regulatory requirements. The Committee also evaluates, on an ongoing basis, the adequacy of the Corporation's processes for identifying and managing environmental, health and safety risks and makes recommendations to the Board of Directors to ensure continual improvement in environmental, health and safety performance. The Committee advises the Board of Directors with respect to OPG's operations and maintenance processes to ensure that the radiological risk to workers, the public and the environment is kept within established safety standards. The Committee also monitors and advises the Board of Directors on environmental trends and developments in other jurisdictions that relate to OPG's operations.

Nuclear Review Committee. The Nuclear Review Committee's mandate is to monitor the nuclear performance of the Corporation, particularly with respect to safety issues. The Committee advises the Board of Directors with respect to policies and strategies to ensure the safe performance of OPG's nuclear operations. The Committee also advises the Board of Directors with respect to compliance with existing laws and regulations that govern OPG's nuclear facilities, including commitments made to the Canadian Nuclear Safety Commission. The Committee is also responsible for reviewing the scope of nuclear performance audit programs and the appointment of external advisors and assessors.

Executive Compensation

The following summary compensation table sets forth the compensation paid by the Corporation for the years ended December 31, 1999, 2000 and 2001 to the Chief Executive Officer, the Chief Operating Officer and each of the Executive Vice-Presidents of the Corporation, including the five most highly compensated executive officers of the Corporation (the "Named Executive Officers"). This table excludes data relating to long-term compensation for the 1999 to 2001 period, as the Corporation did not have any capital stock-related award plans and there was no compensation arising from long-term incentive plans for this period that was paid to these executives in 2001.

Summary Compensation Table

Name and Principal Position	Year	Annual Compensation			All Other Compensation ($)
		Salary ($)	Bonus ($)	Other Annual Compensation ($)[1]	
Ronald W. Osborne, Director, President and Chief Executive Officer	2001 2000 1999	825,000 775,000 750,000	752,813 975,000 900,000	81,841 99,008 91,913	- - -
Graham Brown, Director and Chief Operating Officer	2001 2000	676,000 169,000[3]	353,210 84,500	51,697 19,436	112,500[2] 437,500[2]
Wayne Bingham, Executive Vice-President and Chief Financial Officer	2001 2000 1999	336,000 306,000 234,199[5]	142,128 123,000 135,000	49,294 51,709 39,917	45,000[4] 45,000[4] 122,744[6]
Richard Dicerni, Executive Vice-President and Corporate Secretary	2001 2000 1999	315,000 300,000 260,000	131,670 150,000 117,000	54,666 53,552 50,503	- - 11,452[7]
David Drinkwater, Executive Vice-President – Corporate Development and Legal Affairs	2001 2000 1999	400,000 350,000 335,000	209,000 245,000 157,500	52,628 50,156 48,459	45,000[4] 45,000[4] -
John Murphy, Executive Vice-President – Human Resources	2001 2000	300,000 172,011[8]	112,800 64,000	58,545 38,822	- -
Eugene Preston, Executive Vice-President and Chief Nuclear Officer	2001 2000 1999	1,237,488[9] 1,112,148[10] 847,927[10]	185,981[9] 322,719[10] 720,000[11]	33,250 32,937 26,023	- - 1,372,272[10]

Notes:

(1) Includes car allowances, flexible benefits payments and life insurance taxable benefit.

(2) Includes signing bonus plus moving allowance in 2000 and project incentives for 2001.

(3) Mr. Brown commenced employment on October 1, 2000. His salary on an annual basis would have been $675,000.

(4) Guaranteed transitional award payment per employment contract.

(5) Mr. Bingham commenced employment on March 22, 1999. His salary on an annual basis would have been $300,000.

(6) Payment made to compensate for remuneration foregone at a previous employer.

(7) Payment made to the Ontario Pension Board per employment contract. Mr. Dicerni became a member of the Corporation's pension plan on August 1, 1999.

(8) Mr. Murphy commenced employment on May 17, 2000. His salary on an annual basis would have been $275,000. Prior to commencing employment he resigned as a member of the Board of Directors of OPG. His remuneration as a member of the Board of Directors for 2000 was $15,769 and for 1999 was $38,150.

(9) 2001 salary of US$800,000 has been converted at an average exchange rate of US$1.00 = C$1.5469; 2001 bonus payment of US$116,800 has been converted at the prevailing exchange rates at the time of payment of US$1.00 = $1.5923.

(10) 2000 salary of US$750,000 has been converted at an average exchange rate of US$1.00 = C$1.4829; 2000 bonus payments of US$165,000 and US$50,000 have been converted at the prevailing exchange rates at the time of payment of US$1.00 = C$1.4949 and US$1.00 = C$1.5212, respectively; 1999 salary of US$568,774 has been converted at an average exchange rate of US$1.00 = C$1.4908; and a payment of US$902,395 to settle retirement obligations has been converted at a rate of US$1.00 = C$1.5207.

(11) Bonus of US$500,000 in respect of three prior years was paid on conversion of contract and converted at an exchange rate of US$1.00 = C$1.44.

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 is to provide an incentive to achieve outstanding performance over a longer term than the one-year period covered by annual bonus awards.

The LTIP operates over three-year overlapping periods. Each performance period starts on January 1 of the first calendar year and ends December 31 of the third calendar year. To be eligible for a payout under the LTIP, a participant must be 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 will end on December 31, 2002. The next period commenced January 1, 2001 and will end on December 31, 2003. The most recent period commenced January 1, 2002 and will end on December 31, 2004.

LTIP payouts will be determined based on corporate results achieved during each performance period and paid out in cash. The Human Resources Corporate Governance Committee of the Board will determine 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 will be established. LTIP payouts will not be paid for performance below threshold. Threshold, target and maximum incentive awards will be expressed as a percentage of the participant's average base salary over the three-year performance period.

To recognize the fact that no LTIP payouts would be made until the completion of the first three-year performance period at the end of 2001, an enhanced award opportunity equal to 50% of the award otherwise payable was provided to participants with respect to the 1999-2001 award, as set out in the following table. For example, if a participant's target eligibility is 25% of base salary and performance during the period 1999-2001 was at target levels, the award was increased at the end of 2001 by 50% to 37.5% of base salary. Thereafter, the size of the LTIP award opportunity will remain consistent with the original plan. Consequently, the LTIP potential payouts for 2000-2002 will reflect a lower potential payout than for 1999-2001.

Long-Term Incentive Plans
Awards in Most Recently Completed Financial Year

Actual LTIP pay-outs for the performance period which commenced January 1, 1999 were paid in 2002 and are shown in the table below.

Actual LTIP Pay-outs for the 1999 – 2001 Period Under Non-Securities-Price Based Plans	
Name	**Actual Pay-Out Amount**
Ronald W. Osborne, Director, President and Chief Executive Officer	$587,500
Graham Brown, Director and Chief Operating Officer	-
Wayne Bingham, Executive Vice-President and Chief Financial Officer	$117,750
Richard Dicerni, Executive Vice-President and Corporate Secretary	$109,375
David Drinkwater, Executive Vice-President – Corporate Development and Legal Affairs	$135,625
John Murphy, Executive Vice-President – Human Resources	-
Eugene Preston, Executive Vice-President and Chief Nuclear Officer(1)	US$155,000

Note:
(1) Mr. Preston's LTIP payment is shown in U.S. dollars per his employment contract and was paid at an exchange rate of US$1.00 = C$1.5923.

The following table illustrates the potential future payouts under the LTIP for the two performance periods which commenced on January 1, 2000 and January 1, 2001 for those Named Executive Officers, as of December 31, 2001, who participated in the LTIP. Actual LTIP payouts will not be made until the completion of the three-year performance period and will depend upon performance and the level of the individual's eligible earnings over each of the three-year periods.

Potential Future Payouts in 2003 and 2004 Under Non-Securities-Price Based Plans [1]				
Name	**Performance or Other Period Until Maturation or Payout**	**Threshold ($)**	**Target ($)**	**Maximum ($)**
Ronald W. Osborne, Director, President and Chief Executive Officer	2001-2003 2000-2002	206,000 194,000	413,000 388,000	619,000 581,000
Graham Brown, Director and Chief Operating Officer	2001-2003 2000-2002	203,000 203,000	406,000 406,000	608,000 608,000
Wayne Bingham, Executive Vice-President and Chief Financial Officer	2001-2003 2000-2002	42,000 38,000	84,000 76,000	126,000 114,000
Richard Dicerni, Executive Vice-President and Corporate Secretary	2001-2003 2000-2002	39,000 38,000	79,000 75,000	118,000 112,000
David Drinkwater, Executive Vice-President – Corporate Development and Legal Affairs	2001-2003 2000-2002	50,000 44,000	100,000 88,000	150,000 131,000
John Murphy, Executive Vice-President – Human Resources	2001-2003 2000-2002	38,000 34,000	75,000 69,000	113,000 103,000
Eugene Preston, Executive Vice-President and Chief Nuclear Officer[2]	2001-2003 2000-2002	US$80,000 US$75,000	US$160,000 US$150,000	US$240,000 US$225,000

Notes:

(1) Calculations are based on 2000 and 2001 salary levels.
(2) Mr. Preston's LTIP payment is shown in U.S. dollars per his employment contract, with the exchange rate to be determined at the time of the payment for OPG's accounting purposes.

Pension Plans

Messrs. Osborne, Brown, Bingham, Dicerni, Drinkwater and Murphy 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 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, 2001, 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	$57,068	$76,090	$95,113	$114,135	$133,158
$400,000	$117,068	$156,090	$195,113	$234,135	$273,158
$600,000	$177,068	$236,090	$295,113	$354,135	$413,158
$800,000	$237,068	$316,090	$395,113	$474,135	$553,158
$1,000,000	$297,068	$396,090	$495,113	$594,135	$693,158
$1,200,000	$357,068	$476,090	$595,113	$714,135	$833,158
$1,400,000	$417,068	$556,090	$695,113	$834,135	$973,158
$1,600,000	$477,068	$636,090	$795,113	$954,135	$1,113,158

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

Mr. Osborne's credited service at December 31, 2001 is 8.79 years. For each year of service with the Corporation, he will receive 1.25 years of credited service for purposes of calculating his pension plan benefit. Mr. Osborne's pensionable earnings will be comprised of his base salary and the bonus compensation earned in the year and paid in the following year. On retirement, he will also receive a lump sum retiring allowance equal to his annual base salary.

Mr. Brown's credited service at December 31, 2001 is 1.25 years. Mr. Brown's pensionable earnings include his base salary and any bonus earned in the year and paid in the following year. Mr. Brown's pension is based on the average pensionable earnings in his best 36 consecutive months of employment, this average not to exceed his average base salary and average target bonus during the same period. On termination before the age of 55, he will receive a deferred pension, commencing at age 55, equal to 85% of his annual pension based on service and earnings to the date of such termination. If Mr. Brown retires after age 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. On retirement in accordance with the terms of the pension plans, Mr. Brown will also receive a lump sum retiring allowance equal to his monthly base salary.

Mr. Bingham's credited service at December 31, 2001 is 5.50 years. For each of his first ten years of service with the Corporation, he will receive two years of credited service for purposes of calculating his pension plan benefit. Thereafter he will receive one year credited service for each year of service. Mr. Bingham's pensionable earnings will be comprised of his base salary and the bonus compensation (up to his target bonus) earned in the year and paid in the following year. On retirement after age 55, he will also receive a lump sum retiring allowance equal to his monthly base salary.

Mr. Dicerni's credited service at December 31, 2001 is 32.22 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 earned in the year and paid in the following year.

Mr. Drinkwater's credited service at December 31, 2001 is six 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. In addition, the Corporation guarantees that if Mr. Drinkwater is terminated (other than for cause), prior to age 55, he will receive a total pension of not less than $100,000 per annum payable from age 55. If Mr. Drinkwater retires after age 55 and before age 60, his total pension from the Corporation will not be less than $100,000 per annum. If Mr. Drinkwater retires after age 60, his total pension from the Corporation will not be less than $200,000 per annum.

Mr. Murphy's credited service at December 31, 2001 is 21.58 years. Mr. Murphy's pensionable earnings include his base salary and any bonus earned in the year and paid in the following year. Mr. Murphy's pension is based on the average pensionable earnings in his best 36 consecutive months of employment, this average not to exceed his average base salary and average target bonus during the same period. On termination before the age of 55, he will receive a deferred pension, commencing at age 55, equal to 85% of his annual pension based on service and earnings to the date of such termination. If Mr. Murphy retires after age 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. On retirement in accordance with the terms of the pension plans, Mr. Murphy will also receive a lump sum retiring allowance equal to his monthly base salary.

Mr. Preston will receive a retiring allowance equal to the amount by which his annualized salary determined as of January 31, 2004 exceeds US$300,000, if his employment contract has not been terminated prior to January 31, 2004. Upon payment of the retiring allowance, OPG shall have no further obligation to provide additional retirement funds to Mr. Preston.

Employment Agreements

The Corporation has employment agreements with each of the Named Executive Officers. In addition to their base salary and other LTIP and pension entitlements described above, Messrs. Osborne, Preston, Brown, Bingham, Dicerni, Drinkwater and Murphy are eligible to receive annual cash bonus awards based on the achievement of key corporate, business and individual performance measures.

Mr. Osborne's employment agreement provides that upon involuntary termination without cause Mr. Osborne would receive either one year's notice or, at the Corporation's option, a lump sum payment equal to his base salary plus an amount equal to the annual bonus paid the preceding year, discounted for one year at prevailing interest rates. In addition, all amounts accrued under the Corporation's long term incentive plan will vest immediately and will be paid within 90 days of the date of termination. Mr. Osborne may elect to terminate his employment by giving 180 days' notice if: (1) there is a fundamental change in the policies of the Province relating to the Corporation pursuant to which it is not reasonably possible for Mr. Osborne to continue as President and Chief Executive Officer; or (2) there is a change of control of the Corporation, other than a public offering of shares, to which Mr. Osborne has not consented (such consent not to be unreasonably withheld or delayed). If Mr. Osborne elects to terminate his employment as a result of a fundamental change in policy or a change of control, he will receive the same payments as if he were terminated without cause, except that the notice period shall be two years such two year period to commence on the date on which Mr. Osborne gives notice.

The Corporation has entered into an employment agreement with Mr. Brown under which, in the event that Mr. Brown is terminated without cause by the Corporation, he will be provided a period of notice of one year plus an amount equal to the annual bonus paid for the preceding year, or in lieu of the above, at either Mr. Brown's or the Corporation's option, a lump sum of $1 million. In addition, Mr. Brown will receive any outstanding signing bonus, all amounts accrued under the long-term incentive plan and project initiatives and, if notice of termination is effective before December 31, 2003, relocation expenses to the United Kingdom and reimbursement for any loss on the sale of his home in Canada. Mr. Brown may elect to terminate his employment if: (1) by the end of 2003 no non-government equity has been invested in the Corporation and there is no reasonable prospect of such equity investment in 2004; or (2) there is a change in control of the Corporation, other than a public offering of shares, to which Mr. Brown has not consented (such consent not to be unreasonably withheld or delayed); and, as a result, there is a material change in Mr. Brown's duties or responsibilities. In such event, he will be entitled to receive $1 million plus any outstanding signing bonus and all amounts accrued under the long-term incentive plan and project initiatives.

The Corporation has entered into an employment agreement with Mr. Bingham which provides for guaranteed awards payable in 2000 and 2001. The agreement provided for a payment in 1999 to compensate for remuneration foregone at the previous employer. The agreement provides that in the event that Mr. Bingham is terminated without cause by the Corporation within the first 36 months of his employment he will receive a lump sum equal to two years salary; he will receive 18 months' salary if terminated without cause thereafter.

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. Mr. Dicerni may elect to terminate his employment by giving 60 days' notice.

The Corporation has entered into an employment agreement with Mr. Drinkwater which guarantees awards payable in 2000 and 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. If Mr. Drinkwater is terminated without cause before the age of 55, he will receive an amount by which the aggregate of eighteen months salary plus the target level of his annual bonus exceeds the commuted value of the retiring allowance. 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: (1) there is a fundamental change in the policies of the Province relating to the Corporation, or (2) there is a change of control of the Corporation, other than by 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.

Mr. Preston's employment agreement provides that upon involuntary termination without cause, Mr. Preston would receive 12 months' written notice, or a lump sum in lieu of notice, such lump sum to be calculated on base salary only. Unless extended by mutual agreement, the current employment agreement will terminate as of January 31, 2004, following which he will receive moving expenses to a destination of his choice within North America, provided he returns to the United States within three months of termination of the agreement. Mr. Preston will also receive the purchase price of his home in Canada if not sold within three months of termination of the agreement.

Compensation of Directors

The Corporation's Chairman, William A. Farlinger, is remunerated at a level of $250,000 per annum with such perquisites and benefits provided to senior executives of the Corporation, including pension. Mr. Farlinger's credited service at December 31, 2001, is 6.16 years. At retirement, Mr. Farlinger's pension shall consist of $6,000 per annum for each full year of service, plus a *pro rated* amount for any part years, subject to consumer price index adjustments and with provisions for spousal survivor benefits.

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. The amount of such remuneration is determined by the Board of Directors from time to time. Directors currently receive a $25,000 annual retainer ($15,000 in 2000) plus $900 for each Board and committee meeting attended. In addition to other fees, the chair of each committee is paid a $3,000 annual retainer.

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, 2001. 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 Secretary, 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 Environment and Energy
OEB	-	Ontario Energy Board
OEFC	-	Ontario Electricity Financial Corporation

Technical and Operational Terms

"Acquired Business" refers to Ontario Hydro's electricity generation business, the assets, liabilities, employees and obligations of which were purchased and assumed by OPG on April 1, 1999 pursuant to the *Electricity Act, 1998* (Ontario);

"aggregator", **"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);

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

"**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;

"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;

"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;

“municipal electrical utility” or “**MEU**” refers to an entity that purchases power at wholesale and distributes it at retail prices to connected customers within a defined geographical area, typically a city or town;

“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;

“Open Access” 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* and the OEB Standard Supply Service Code;

“stranded debt” is defined under the *Electricity Act, 1998* 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.